UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended DECEMBER 31, 2001

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________ to __________

Commission File Number: 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.

(Exact name of Registrant as specified in its charter)

Delaware	**39-1715850**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1100 Louisiana
Suite 3300
Houston, Texas 77002
(Address of principal executive offices and zip code)

(713) 650-8900
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Class A Common Units	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

As of February 20, 2002, the aggregate market value of the Registrant's Class A Common Units held by non-affiliates of the Registrant was $1,316,129,620 based on the reported closing sale price of such units on the New York Stock Exchange on that date.

As of February 20, 2002, there were 29,053,634 of the Registrant's Class A Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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This Annual Report on Form 10-K contains forward-looking statements. These statements are based on the Partnership's beliefs as well as assumptions made by and information currently available to the Partnership. When used in this document, the words "anticipate," "believe," "expect," "estimate," "forecast," "project," and similar expressions identify forward-looking statements. These statements reflect the Partnership's current views with respect to future events and are subject to various risks, uncertainties and assumptions including:

- *the Partnership's dependence upon adequate supplies of and demand for western Canadian crude oil,*
- *the Partnership's ability to acquire other companies and assets and successfully integrate them into its business,*
- *the price of crude oil and the willingness of shippers to ship crude oil,*
- *regulation of the Partnership's tariffs on its Lakehead and North Dakota Systems by the Federal Energy Regulatory Commission and the possibility of unfavorable outcomes of future tariff proceedings, and*
- *the effects of competition, in particular, by other pipeline systems.*

If one or more of these risks or uncertainties materialize, or if the underlying assumptions prove incorrect, actual results may vary materially from those described in this Form 10-K. Except as required by applicable securities laws, the Partnership does not intend to update these forward-looking statements. For additional discussion of such risks, uncertainties and assumptions, see "Items 1 & 2. Business and Properties—Risk Factors" included elsewhere in this Form 10-K.

Glossary

The following abbreviations, acronyms, or terms used in this Form 10-K are defined below:

Act	Pipeline Safety Act
ADOE	Alberta Department of Energy
Bbl	Barrel of liquids (approximately 42 U.S. gallons)
Bpd	Barrels per day
CAA	Clean Air Act
CAPP	Canadian Association of Petroleum Producers
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
Cdn.	Amount denominated in Canadian dollars
CWA	Clean Water Act
DNR	Department of Natural Resources
DOT	Department of Transportation
East Texas	Enbridge (East Texas) L.L.C. and subsidiaries
East Texas System	Gathering, treating and processing natural gas assets owned by East Texas
EBITDA	Earnings before Interest, Taxes, Depreciation, and Amortization
Enbridge	Enbridge Inc.
Enbridge Mustang	Enbridge Holdings (Mustang) Inc.
Enbridge North Dakota	Enbridge Pipelines (North Dakota) L.L.C.
Enbridge System	Canadian portion of the System
Enbridge Pipelines	Enbridge Pipelines Inc.
Enbridge U.S.	Enbridge (U.S.) Inc.
EPA	Environmental Protection Agency
Epu	Earnings per unit
Equilon	Equilon Pipeline Company L.L.C.
Express Pipeline	Express Pipeline Ltd.
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
General Partner	Enbridge Energy Company, Inc.
ICA	Interstate Commerce Act
Lakehead System	U.S. portion of the System
LIBOR	London Interbank Offered Rate—British Bankers Association's average settlement rate for deposits in U.S. dollars
Line 9	A section of the Enbridge System that extends from Sarnia, Ontario to Montreal, Quebec
Midcoast	Midcoast Energy Resources, Inc.
Mmbtu/d	Million British thermal units per day
MMcf/d	Million cubic feet per day
Mobil	Mobil Pipe Line Company
Mustang	Mustang Pipe Line Partners
NEB	National Energy Board
NGL or NGLs	Natural gas liquids
North Dakota System	Liquids petroleum pipeline system owned by Enbridge North Dakota
NYSE	New York Stock Exchange

Operating Partnership	Enbridge Energy, Limited Partnership
OPS	Office of Pipeline Safety
PADD	Petroleum Administration for Defense Districts
PADD 2	Consists of Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee and Wisconsin
PADD 3	Consists of Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas
Partnership Agreements	Amended and Restated Agreements of Limited Partnership of the Partnership and Operating Partnership
Partnership	Enbridge Energy Partners, L.P. and subsidiaries
PPIFG-1	Producer Price Index for Finished Goods minus 1%
RCRA	Resource Conservation and Recovery Act
SEC	Securities and Exchange Commission
SEP II	System Expansion Program II
Settlement Agreement	A FERC approved settlement agreement, signed October 1996
SFAS	Statement of Financial Accounting Standards
SFPP	Santa Fe Pacific Pipelines, L.P.
System	The combined operations of the Lakehead System and the Enbridge System
Tariff Agreement	A 1998 offer of settlement filed with the FERC
Terrace	Terrace Expansion Program
Tidal	Tidal Energy Marketing Inc.

PART I

Items 1 & 2. Business and Properties

Overview

The Partnership is a publicly traded Delaware limited partnership (NYSE symbol: "EEP"), that owns and operates a regulated liquids pipeline business and a natural gas gathering and processing business in the United States. The Partnership was formed in 1991 to acquire, own, and operate the Lakehead System, a regulated crude oil and NGL pipeline business of the General Partner, a wholly-owned subsidiary of Enbridge Pipelines. Enbridge Pipelines is a Canadian company ultimately owned by Enbridge of Calgary, Alberta, Canada. During 2001, the Partnership acquired the North Dakota System from Enbridge and the East Texas System from a non-related third party. The assets acquired are held in subsidiaries owned, directly or indirectly, 100% by the Partnership.

The General Partner owns a 11.8% limited partner interest (in the form of 3,912,750 Class B Common Units) and a 1% general partner interest in the Partnership, as well as a 1% general partner interest in the Operating Partnership. The remaining 87.2% limited partner interest in the Partnership is represented by 29,053,634 publicly traded Class A Common Units.

The most significant asset and the largest contributor to Partnership earnings continues to be the Lakehead System. For 2001, approximately 98% of the consolidated earnings of the Partnership were derived from the Lakehead System. The Lakehead System in the United States and the Enbridge System in Canada together form the longest liquid petroleum pipeline system in the world. In this document, the combined operations of the Lakehead System and the Enbridge System are referred to as the System. The Partnership and Enbridge Pipelines transport crude oil and other liquid hydrocarbons for others through the System. The System is the primary transporter of crude oil from western Canada to the United States and is the only pipeline that transports crude oil from western Canada to the province of Ontario, Canada. The System serves all the major refining centers in the Great Lakes region of the United States, as well as Ontario and, through interconnects, the Patoka/Wood River pipeline hub and refining center in southern Illinois.

The System extends from Edmonton, Alberta, across the Canadian prairies to the U.S. border near Neche, North Dakota. From Neche the System continues to Superior, Wisconsin where it splits into two branches, with one branch traveling through the upper Great Lakes region and the other through the lower Great Lakes region of the United States. Both branches reenter Canada near Marysville, Michigan. From Marysville the System continues to Toronto, Ontario with lateral lines to Nanticoke, Ontario and the Buffalo, New York area. Another part of the System, Line 9, originates in Montreal, Quebec, and continues west to serve Sarnia, Ontario refineries. The System is approximately 3,100 miles long, of which approximately 1,880 miles are in the United States.

Shipments tendered to the System primarily originate in oil fields in the western Canadian provinces of Alberta, Saskatchewan, Manitoba and British Columbia and in the Northwest Territories of Canada. Shipments reach the System through facilities owned and operated by third parties or affiliates of Enbridge Pipelines. Deliveries from the System are currently made in the prairie provinces of Canada and, through the Lakehead System, to the Great Lakes and Midwest regions of the United States and to the Province of Ontario. These deliveries are made principally to refineries either directly or through connecting pipelines of other companies.

All scheduling of shipments (including routes and storage) is handled by Enbridge Pipelines in coordination with the Partnership. The Lakehead System includes 15 connections to pipelines and refineries at various locations in the United States, including the refining areas in and around Chicago, Illinois; Minneapolis-St. Paul, Minnesota; Detroit, Michigan; Toledo, Ohio; Buffalo and Patoka/Wood River. The Lakehead System has three main terminals at Clearbrook, Minnesota, Superior and Griffith, Indiana. The terminals are used to gather crude oil prior to injection into the Lakehead System and to provide tankage in order to allow for more flexible scheduling of oil movements.

Business Strategy

The primary strategy of the Partnership is to grow cash distributions through the profitable expansion of the Lakehead System and through development and acquisition of complementary businesses with similar risk profiles to the Partnership's current crude oil and NGL transportation business. The Partnership plans to expand the Lakehead System's capacity through the construction of Terrace Phase III and to enhance the efficiency of the system where appropriate.

The Partnership will continue to analyze potential acquisitions, with a focus on crude oil, refined products and natural gas pipelines, terminals and related facilities. Major oil and gas companies have sold non-strategic assets in recent years, continuing the trend of rationalization of the energy infrastructure in the United States. The Partnership expects this trend to continue and believes it is well positioned to participate in these opportunities. The Partnership will seek out opportunities throughout the United States, particularly in the U.S. Gulf Coast area.

Properties

The Lakehead System consists of approximately 3,300 miles of pipe with diameters ranging from 12 inches to 48 inches, 63 pump station locations with a total of approximately 667,000 installed horsepower and 58 crude oil storage tanks with an aggregate working capacity of approximately 10 million barrels. The Lakehead System requires approximately 14 million barrels of oil in the pipeline for operation, all of which is owned by the shippers. The Lakehead System regularly transports up to 43 different types of liquid hydrocarbons including light, medium and heavy crude oil (including bitumen), condensate, synthetic crudes and NGL.

The Lakehead System is comprised of a number of separate segments as follows:

- Canadian border to Clearbrook segment including portions of four pipelines consisting of 18-, 20-, 26-, and 34-inch diameter pipe, respectively, and a fifth line consisting of 36- and 48-inch diameter pipe with a total annual capacity of 1,727,000 bpd;
- Clearbrook to Superior segment including portions of three pipelines consisting of 18-, 26-, and 34-inch diameter pipe, respectively, with a total annual capacity of 1,395,000 bpd. This segment includes approximately 80 miles of 48-inch pipeline looping that increases the capacity of this segment;
- Superior to Marysville segment consisting of 30-inch diameter pipe with a total annual capacity of 491,000 bpd;
- Superior to Chicago area segment including two pipelines of 24- and 34-inch diameter pipe with a total annual capacity of 889,000 bpd;
- Chicago area to Marysville segment consisting of a 30-inch diameter pipe with a total annual capacity of 333,000 bpd; and
- Canadian border to Buffalo segment consisting of 12- and 20-inch diameter pipe with a total annual capacity of 74,000 bpd.

Estimated annual capacities noted above take into account receipt and delivery patterns and ongoing pipeline maintenance, and reflect achievable pipeline capacity over long periods of time.

The Partnership believes that the Lakehead System has been constructed and is maintained substantially in accordance with applicable federal, state and local laws and regulations, standards prescribed by the American Petroleum Institute, American Society of Mechanical Engineers or other technical associations and accepted industry practice. The Partnership attempts to control external corrosion of the pipeline through the use of pipe coatings and cathodic protection systems and monitors the integrity of the Lakehead System through a program of periodic internal inspections using electronic instruments. At intervals not exceeding 3 weeks, but at least 26 times each calendar year, the entire pipeline right of way is inspected from the air. In addition, trained and skilled operators use computerized monitoring systems to identify pressure drops or abnormal conditions that might indicate potential disruptions in flow, and operate remote-controlled valves and pumps that allow the Lakehead System to be shut down quickly if necessary.

Acquisitions

During 2001, the Partnership began executing its strategic plan to diversify its energy transportation business. Effective May 18, 2001, the Partnership acquired the North Dakota System from Enbridge for $35.4 million, which included working capital and transaction costs. This system gathers crude oil from approximately 36 oil fields in North Dakota and Montana and receives Canadian crude oil via an interconnect with Enbridge's gathering system in Saskatchewan, Canada. Deliveries are made primarily to the Lakehead System at Clearbrook.

The North Dakota System includes 330 miles of crude oil gathering lines connected to a 620-mile trunk line. Pipe diameters range from 4 inches to 16 inches and have an operating capacity of 84,000 bpd. The North Dakota System also has 15 pump stations and 12 storage tank facilities that store more than 715,000 bbls of crude oil.

Effective November 30, 2001, the Partnership acquired natural gas gathering, treating and processing assets located in east Texas for cash of $230.5 million. The East Texas System purchases natural gas directly from producers and/or provides downstream transportation services to the major intrastate and interstate pipelines in east Texas. The East Texas System also delivers natural gas to local industrial and power plant markets, which are connected directly to the pipeline system.

The East Texas System includes approximately 2,000 miles of gathering and transmission pipelines and 37 field compressors with 35,000 total horsepower. The gathering assets consist of a network of pipelines that collect natural gas from producing wells and transport it to other pipelines for further transmission. Approximately 400,000 Mmbtu/d of natural gas flows into the pipelines from 440 receipt points. Much of the pipeline is 8 inch to 12 inch diameter pipe with smaller 4 inch to 6 inch gathering lines and larger 14 inch to 20 inch transmission lines creating an integrated gathering and intrastate transportation system. The Partnership derives revenues from gathering systems by transporting natural gas owned by others through its pipelines for a transportation fee, and by purchasing natural gas and utilizing its pipelines to transport the natural gas to a customer in another location where it is resold.

The East Texas System includes four sour gas treating facilities that remove hydrogen sulfide, carbon dioxide and water from the natural gas stream. These plants have a combined capacity of approximately 595 MMcf/d. Sulfur recovery and handling services are provided at some plants, and the East Texas System has the ability to move sour gas through a significant part of its gathering lines. The revenue for these services are incremental to those collected for transporting the natural gas.

The East Texas System also includes three cryogenic gas processing plants, which process natural gas gathered by its pipelines. The plants allow the extraction of NGLs from a natural gas stream. Gas is processed when the market value of the NGLs and processed gas exceeds the market value of the unprocessed natural gas. The Partnership's natural gas processing revenues are realized from the extraction and sale of NGLs as well as the sale of the residual natural gas.

Title to Properties

The Partnership conducts business and owns properties located in eleven states: Wisconsin, Minnesota, Illinois, Indiana, Michigan, Ohio, New York, Montana, North Dakota, Texas and Louisiana. In general, the Lakehead, North Dakota and East Texas Systems are located on land owned by others and are operated under perpetual easements and rights of way, licenses or permits that have been granted by private land owners, public authorities, railways or public utilities.

The pumping stations, tanks, terminals and certain other facilities of the systems are located on land that is owned by the Partnership, except for five pumping stations that are situated on land owned by others and used by the Partnership under easements or permits. An affiliate of the General Partner acquired parcels of property for the benefit of the Partnership to allow for the construction of SEP II. The affiliate is continuing to sell these parcels to third parties while retaining an easement for the benefit of the Partnership. See "Item 13. Certain Relationships and Related Transactions."

Substantially all of the Lakehead System assets are subject to a first mortgage securing indebtedness of the Operating Partnership.

Risk Factors

An inadequate supply of western Canadian crude oil can adversely affect the Partnership's business. The supply of western Canadian crude oil was negatively impacted by low world oil prices in 1998 and early 1999. Since oil prices stabilized in late 1999, there has been a shift in focus to natural gas drilling rather than oil, due to the favorable natural gas price environment. The Partnership's ability to increase deliveries and to expand the Lakehead System in the future also depends upon increased supplies of western Canadian crude oil. For a discussion of the forecast for the future supply of crude oil produced in western Canada, see "—Supply of and Demand for Western Canadian Crude Oil."

Demand for western Canadian crude oil and NGL in the geographic areas served by the Lakehead System is affected by the delivery of other crude oil and refined petroleum products into the same areas. Existing pipeline capacity for the delivery of crude oil to the U.S. upper Midwest, the primary destination market served by the Lakehead System, exceeds current refining capacity. The Partnership believes that the System has several advantages over other transporters of crude oil with which it competes and the System is among the lowest cost transporters of crude oil and NGL in North America based on costs per barrel mile transported. See "—Competition."

Commodity price exposure is inherent in gas purchase and resale activities and in gas processing, both of which are conducted on the East Texas System. To the extent the Partnership engages in hedging activities to reduce the commodity price exposure, it may be prevented from realizing the benefits of price increases above the level of the hedges. Further, hedging contracts are subject to the risk that the other party may prove unable or unwilling to perform its obligations under such contracts.

The Partnership is subject to the risk that changes may occur in existing economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices. Any of these factors could reduce the demand for crude oil, other liquid hydrocarbons and natural gas in the areas in which deliveries are made by the Partnership's systems. In addition, reduced throughput on the systems could result from testing, line repair, reduced operating pressures, reduced crude oil and natural gas supply, regulatory restrictions on system utilization or other causes.

The operations of the Partnership are subject to federal and state laws and regulations relating to environmental protection and operational safety; compliance with these regulations may increase the Partnership's costs and reduce its revenues. Although the Partnership believes that the operations of its systems are in substantial compliance with applicable environmental and safety regulations, risks of substantial costs and liabilities are inherent in pipeline operations, and such costs and liabilities could be incurred. See "—Environmental and Safety Regulation."

The Partnership periodically files tariff rate increases and decreases with FERC for the Lakehead and North Dakota Systems. A tariff agreement between the Partnership and customer representatives sets forth parameters governing the tariff changes associated with SEP II, Terrace, and related expansion projects on the Lakehead System. Notwithstanding this agreement, any shipper who is not a party to the agreement could challenge any existing or future rate filings. Any challenge, if successful, could have a material adverse effect on the Partnership. For a discussion of FERC regulation, Partnership tariff rates and the tariff agreement, see "—Regulation" and "—Tariffs."

The rates charged for certain services related to interconnects with other interstate pipelines on the East Texas System are regulated by the FERC under the Natural Gas Policy Act of 1978. Although the East Texas System is not subject to FERC jurisdiction under the Natural Gas Act, the FERC continually proposes and implements new rules and regulations affecting the natural gas industry and rates subject to the FERC's jurisdiction. New initiatives or orders could impact the rates charged for services.

The Partnership's ability to increase earnings and cash distributions will depend, in part, upon the ability to identify and complete acquisition opportunities on favorable terms. Growth through acquisitions, and the future operating results and success of such acquisitions, may be subject to the effects of, and changes in, laws and regulations, political and economic developments, inflation rates, taxes, financing capability and operating conditions.

The Partnership's General Partner is related to both Enbridge and the Partnership, which could result in conflicts of interest between the Partnership and Enbridge from time to time. The partnership agreement limits the fiduciary duties of the General Partner to the Partnership, and the unit holders have effectively consented to various actions and conflicts that might otherwise be deemed a breach of fiduciary or other duties under law. Conflicts could arise regarding time and amount of capital expenditures, borrowing, issuance or purchase of units, and allocation of resources. As a result of the reversal of the flow of Line 9 in 1999, Enbridge Pipelines competes with the Partnership to supply crude oil to the Ontario market.

Regulation

FERC Regulation

The Partnership's interstate common carrier pipeline operations are subject to rate regulation by the FERC under the version of the ICA applicable to oil pipelines. The ICA requires that petroleum products and crude oil common carrier pipeline rates be just, reasonable and non-discriminatory. The ICA permits challenges to new, changed and existing rates through either a "protest" or "complaint." At the FERC, a protest normally applies only to a proposed change in a pipeline's rates or practices and subjects the pipeline to a forward-looking investigation and possible refund obligation. The FERC can also choose to suspend the proposed change for up to seven months from the proposed date of the change. A complaint, by comparison, typically applies to an existing rate or practice and subjects the pipeline, in some circumstances, to possible two-year retroactive liability for past rates or practices found to be unlawful.

The FERC utilizes a simplified ratemaking methodology for oil pipelines that prescribes an indexing methodology for setting rate ceilings. As described in FERC Orders No. 561 and No. 561-A, the index used is the PPIFG-1. Rate ceiling levels are increased or decreased each July 1. The PPIFG-1 index for use beginning on July 1, 2001, was approximately 2.8%. Inflationary rate changes prescribed under the FERC's indexing methodology may be different than changes in the Partnership's costs. Indexed rates are subject both to protests and to complaints, but in either case the FERC's existing regulations specify that the party challenging a rate must show reasonable grounds for asserting that the amount of any rate increase resulting from application of the index is so substantially in excess of the pipeline's increase in costs as to be unjust and unreasonable (or alternatively, that the amount of any rate decrease is so substantially less than the actual cost decrease incurred by the pipeline that the rate is unjust and unreasonable).

The FERC has stated that, as a general rule, crude oil pipelines must utilize the indexing methodology to change rates. However, the FERC has retained cost-based ratemaking, market-based rates and settlements as alternatives to the indexing approach. A pipeline can follow a cost-based approach when it can demonstrate that there is a substantial divergence between the actual costs experienced by the carrier and the rates resulting from application of the index. Under FERC's cost-based methodology, crude oil pipeline rates are permitted to generate operating revenues, based on projected volumes, not greater than the total of operating expenses, depreciation and amortization, federal and state income taxes and an overall allowed rate of return on the pipeline's rate base. In addition, a pipeline can charge market-based rates if it first establishes that it lacks significant market power in a particular relevant market, and a pipeline can establish rates pursuant to a settlement if agreed upon by all current shippers. Initial rates for new services can be established through a cost-based filing or through an uncontested agreement between the pipeline and at least one shipper not affiliated with the pipeline.

Other Regulation

The governments of the United States and Canada have, by treaty, agreed to ensure nondiscriminatory treatment for the passage of oil and gas through the pipelines of one country across the territory of the other. Individual border crossing points require U.S. government permits that may be terminated or amended at the will of the U.S. government. These permits provide that pipelines may be inspected by or subject to orders issued by federal or state government agencies.

Tariffs

Rate Cases

The Partnership had several rate cases pending before the FERC during the period from 1992 to 1996. The primary issue was the applicability of the FERC's Opinion 154-B/C trended original cost methodology. In 1995 and 1996, the FERC issued decisions on the Partnership's 1992 tariff rate increase that determined the Partnership was entitled to use the FERC's Opinion No. 154-B/C rate methodology, although it was not entitled to recover in its cost of service a tax allowance with respect to income attributable to limited partners who are not corporations or other similar entities.

In October 1996, the FERC approved the Settlement Agreement between the Partnership, CAPP, and ADOE on all then-outstanding contested tariff rates. The Settlement Agreement provided for a tariff rate reduction of approximately 6% and total rate refunds and interest of $120.0 million through the effective date of October 1, 1996, with interest accruing thereafter on the unpaid balance. Effective November 22, 1999, the $120.0 million refund and related interest were fully repaid.

The Settlement Agreement also provided for the terms of an incremental tariff rate surcharge for a period of 15 years to recover the cost of, and allow a return on, the Partnership's investment in SEP II. The rate of return on this investment is based, in part, on the utilization level of the additional capacity constructed. As specified in the Settlement Agreement, higher utilization results in a greater rate of return, subject to a minimum and maximum rate of return of 7.5% and 15.0%, respectively. The tariff rate surcharge is recomputed on a cost of service basis and filed with FERC each year. The Settlement Agreement further provided that the agreed underlying tariff rates would be subject to indexing as prescribed by FERC regulation and that CAPP and ADOE would not challenge any rates within the indexed ceiling for a period of five years, which expired in October 2001. See

"Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations,—Other Matters,—Regulatory Matters."

Tariff Agreement

In 1998, the Partnership filed the Tariff Agreement with the FERC to facilitate the filing of tariff rate surcharges in late 1998 and early 1999. This filing consolidated the 1996 Settlement Agreement for SEP II and other significant agreements with customers concerning Terrace and the transportation of heavy crude oil. The FERC found the Tariff Agreement a reasonable compromise and approved it on the grounds that it is fair, reasonable, and in the public interest.

With respect to Terrace, the Tariff Agreement included terms governing a tariff surcharge associated with the project. A fixed toll increase of Cdn. $0.05 per barrel for the movement of light crude oil from Edmonton to the Chicago area was allocated approximately Cdn. $0.02 ($0.013 U.S.) to the Partnership and Cdn. $0.03 to Enbridge. Effective April 1, 2001, Enbridge and the Partnership agreed to reallocate the Cdn. $0.05 per barrel Terrace toll surcharge, Cdn. $0.04 ($0.026 U.S.) to the Partnership and Cdn. $0.01 to Enbridge. This reallocation is permitted under the terms of the Agreement and was done in an effort to rebalance the project economics between the parties as a result of volume shortfalls, for which the Partnership is completely at risk. This toll will be in effect until April 1, 2004, when, absent any agreement from Enbridge stating otherwise, the toll allocation to the Partnership will change to Cdn. $0.01 ($0.007 U.S.) per barrel. The Terrace incremental toll is also subject to increase or decrease based on changes in other defined circumstances. The portion of the agreement associated with Terrace also established in-service and notice dates for future phases of the expansion program. CAPP provided notice to construct Phase III of Terrace in June 2001. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations,—Other Matters,—Future Prospects,—Terrace Expansion Program."

Other Pipeline Rate Cases

On January 13, 1999, the FERC issued Opinion No. 435 in a case involving SFPP, which addressed various issues of interest to FERC-regulated publicly traded partnerships and other oil pipelines. These included application of FERC's Opinion No. 154-B/C rate methodology and income tax allowances for publicly traded partnerships. The FERC issued rehearing orders on May 17, 2000 (Opinion No. 435-A) and September 13, 2001 (Opinion No. 435-B) that largely reconfirmed the rulings in Opinion No. 435. These orders remain subject to further rehearing on certain issues, as well as judical review. If the SFPP opinion is not changed on further rehearing by FERC or on review by a court of appeals, and if it were applied to the Partnership in some future rate proceedings, the impact to the Partnership, positive or negative, would be dependent upon the specific application of the rulings in that opinion to the Partnership.

Many of the ratemaking issues contested in the Partnership's rate cases, in particular the FERC's oil pipeline ratemaking methodology, have not been reviewed by a federal appellate court. Judicial review, whether or not in a case directly involving the Partnership, could ultimately result in the implementation of alternative ratemaking methodologies that could have a material adverse effect on the Partnership.

Tariffs

Under published tariffs for transportation on the Lakehead System, the rates for light crude oil from key receipt locations to principal delivery points at January 1, 2002 (including the tariff surcharges related to SEP II and Terrace) are set forth below.

	Published Tariff Per Barrel
Canadian border near Neche to Clearbrook	$0.171
Canadian border near Neche to Superior	$0.334
Canadian border near Neche to Chicago area	$0.683
Canadian border near Neche to Marysville area	$0.816
Canadian border near Neche to Buffalo area	$0.836
Chicago to the international border near Marysville	$0.302

The rates at January 1, 2002 for medium and heavy crude oils are higher and those for NGL are lower than the rates set forth in the table to compensate for differences in costs for shipping different types and grades of liquid hydrocarbons. The Partnership periodically adjusts its tariff rates as allowed under FERC's indexing methodology and the Tariff Agreement and will file an updated SEP II surcharge to be effective April 1, 2002. This filing will include any differences between the SEP II surcharge filed in 2001 and actual results for the year, as well as an estimate for 2002. Overall, the Partnership believes that the surcharge will remain relatively consistent with 2001 levels.

Deliveries from the Lakehead System

Deliveries from the Lakehead System are made in the Great Lakes and Midwest regions of the United States and in Ontario, principally to refineries, either directly or through connecting pipelines of other companies. Major refining centers within these regions are located near Sarnia, Nanticoke, Toronto, Minneapolis-St. Paul, Superior, Chicago, the Patoka/Wood River area, Detroit, Toledo, and Buffalo areas. Crude oil and NGL transported by the Lakehead System are feedstock for refineries and petrochemical plants.

The U.S. government segregates the United States into five PADDs, for purposes of its strategic planning to ensure crude oil supply to key refining areas in the event of a national emergency. The oil industry utilizes these districts in reporting statistics regarding oil supply and demand. The Lakehead System services the northern tier of PADD 2. U.S. governmental publications project that crude oil demand in this area will remain relatively constant over the next 10 years. In addition, these publications project the total supply of crude oil, from producing areas in the U.S. southwest, Rocky Mountains and Midwest that currently serve the entire PADD 2 market, to decline in the near term as reserves are depleted, resulting in a need for additional supplies of crude oil to replace the continuing demand. As a result of these factors, the Partnership believes that the Lakehead System will be able to exceed its 2001 level of deliveries into PADD 2 during the next 10 years.

The following table sets forth Lakehead System average deliveries per day and barrel miles for each of the years in the five-year period ended December 31, 2001.

	Deliveries				
	2001	2000	1999	1998	1997
	(Thousands of bpd)				
United States					
Light crude oil	292	321	299	338	282
Medium and heavy crude oil	663	630	575	627	652
NGL	5	25	24	27	26
Total United States	960	976	898	992	960
Ontario					
Light crude oil	174	174	282	366	355
Medium and heavy crude oil	77	85	87	97	98
NGL	104	103	102	107	99
Total Ontario	355	362	471	570	552
Total Deliveries	1,315	1,338	1,369	1,562	1,512
Barrel miles (billions per year)	333	341	350	391	389

Supply of and Demand for Western Canadian Crude Oil

Supply

Substantially all of the liquid petroleum delivered through the Lakehead System originate in oilfields in western Canada. The Lakehead System also receives:

- U.S. and Canadian production at Clearbrook through a connection with the North Dakota System;
- U.S. production at Lewiston, Michigan; and
- both U.S. and offshore production in the Chicago area.

Changes in supply from western Canada directly affect movements through the Enbridge System and, therefore, the supply available for transportation through the Lakehead System. Enbridge regularly prepares forecasts of western Canadian crude oil, which take into account deliveries on the Lakehead System. This is a long-term outlook, which incorporates updated supply projections from producers of both conventional and non-conventional sources of crude oil. The forecast includes supply from existing operations, proposed expansions of existing operations and production from selected projects proposed for development.

The forecast developed by Enbridge in early 2002 projects that the supply of western Canadian crude oil will be approximately 2.1 million bpd in 2002 and approximately 2.2 million bpd in 2003. This forecast projects the supply of crude oil to rise to approximately 2.3 million bpd in 2004 and to approximately 2.8 million bpd by 2011. The forecast was made subject to numerous uncertainties and assumptions, including a crude oil price ranging from $23-$26 per bbl from 2002 to 2011. On February 20, 2002, the benchmark West Texas Intermediate crude oil price closed at $20.29 per bbl.

The Partnership believes that the outlook for increased crude oil production in western Canada continues to be positive, as evidenced by the Enbridge forecast and CAPP's request to proceed with Terrace Phase III. The timing of growth in the supply of western Canadian crude oil, however, will depend upon the level of crude oil prices, oil drilling activity and the timing of completion of projects to produce heavy and synthetic oil from the Alberta oil sands. The Partnership anticipates that 2002 deliveries on the Lakehead System will average approximately 1.33 million to 1.40 million bpd based on the most recent survey of shippers.

Demand

The Lakehead System services the northern tier of PADD 2. The Partnership believes that modestly increasing crude oil demand and declining inland U.S. domestic production will contribute to an increasing need to import crude oil into PADD 2. The Partnership also believes that PADD 2 will continue to provide an excellent market for western Canadian producers as returns to crude oil producers are expected to be attractive. Moreover, the Partnership believes that PADD 2 will remain the most attractive market for western Canadian supply since it is currently the largest North American processor of western Canadian heavy crude oil and has the most refinery processing capacity available to Canadian producers.

Although western Canadian heavy crude oil producers experience competition from Venezuelan and Mexican heavy crude oil in PADD 2, western Canadian heavy crude oil is expected to remain the largest heavy supply source for the region. The Partnership believes that Latin American heavy crude oil will continue to provide modest amounts of supply to the PADD 2 region. The Partnership expects that producers of Latin American heavy crude oil will focus on the PADD 3 and Asian markets, where processing arrangements with refineries are available.

The most recent Enbridge forecast projects demand for exports from western Canada to the United States to increase to approximately 1.67 million bpd in 2006 and to approximately 2.0 million by 2011. The 2011 forecast exports to the U.S. market is 700,000 bpd higher than expected 2002 exports. PADD 2 is expected to receive approximately 1.30 million bpd in 2006, and 1.54 million bpd in 2011.

Demand for crude oil and NGL in the Province of Ontario is expected to remain at approximately 580,000 bpd over the next 10 years. Since 1999, the Partnership's deliveries to the Province of Ontario have been impacted by the reversal of Line 9 from Montreal to Sarnia. The Partnership's deliveries to the Province of Ontario are forecasted to be approximately 400,000 bpd throughout the forecast period.

Customers

The Lakehead System operates under month-to-month transportation arrangements with its shippers. During 2001, 39 shippers tendered crude oil and NGL for delivery through the Lakehead System. These customers included integrated oil companies, major independent oil producers, refiners and marketers. Shipments by the top ten shippers during 2001 accounted for approximately 89% of total revenues during that period. Revenue from BP Canada Energy Company and ExxonMobil Canada Energy accounted for approximately 24% and 20%, respectively, of total operating revenue generated by the Lakehead System during 2001. The remaining shippers each accounted for less than 10% of total revenues. See Note 10 to the Partnership's Consolidated Financial Statements.

Capital Expenditures

In 2001, the Partnership made capital expenditures of $35.0 million, of which $9.4 million was for pipeline system enhancements, $9.3 million for core maintenance activities and $16.3 million for Terrace. These amounts do not include the acquisition costs for the North Dakota and the East Texas Systems. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Taxation

For U.S. federal and state income tax purposes, the Partnership is not a taxable entity. Federal and state income taxes on Partnership taxable income are borne by the individual partners through the allocation of Partnership taxable income. Such taxable income may vary substantially from net income reported in the statement of income.

Competition

Because pipelines are the lowest cost method for intermediate and long haul movement of crude oil over land, the System's most significant existing competitors for the transportation of western Canadian crude oil are other pipelines. In 2001, the Enbridge System transported approximately 65% of total western Canadian crude oil production. The remainder of 2001 western Canadian crude oil production was refined in Alberta or Saskatchewan or transported through other pipelines. Of the pipelines transporting western Canadian crude oil out of Canada, the System provides approximately 75% of the total pipeline design capacity. The remaining 25% of design capacity is shared by five other pipelines transporting crude oil to British Columbia, Washington, Montana, and other states in the U.S. Northwest.

Competition among common carrier pipelines is based primarily on transportation charges, access to producing areas and proximity to end users. The Partnership believes that high capital requirements, environmental considerations and the difficulty in acquiring rights of way and related permits make it difficult for a competing pipeline system comparable in size and scope to the System to be built in the foreseeable future.

Express Pipeline owns and operates a 170,000 bpd capacity pipeline that carries western Canadian crude oil to the U.S. Rocky Mountain region, where it connects to a 125,000 bpd capacity pipeline system. This connecting pipeline serves the Patoka/Wood River market area. Express Pipeline began service in early 1997. The System, however, offers lower tolls into Chicago and Patoka than Express Pipeline and competitive tolls into Wood River. In addition, the System does not require shipper volume commitments as currently required by Express Pipeline.

The System encounters competition in serving shippers to the extent that shippers have alternative opportunities for transporting liquid hydrocarbons from their sources to customers. In selecting the destination for their supplies of crude oil, sellers generally desire to use the alternative that results in the highest return to them. Generally, it is expected that sellers will receive the highest return from markets served by the System, but alternate markets may, for periods of time, offer equal or better returns for the seller. Such markets could potentially include the U.S. Rocky Mountain region for sweet crude oil and the state of Washington market for light sour crude oil.

In the United States, the Lakehead System encounters competition from other crude oil and refined product pipelines and other modes of transportation delivering crude oil and refined products to the refining centers of Minneapolis-St. Paul, Chicago, Detroit and Toledo and the refinery market and pipeline hub located in the Patoka/Wood River area. The Lakehead System transports approximately 54% of all crude oil deliveries into the Chicago area, approximately 86% of all crude oil deliveries into the Minneapolis-St. Paul area and approximately 62% of all deliveries of crude oil to Ontario.

Environmental and Safety Regulation

General

The operations of the Partnership are subject to federal, state and local laws and regulations relating to protection of the environment and safety. Although the Partnership believes that the operations of the Lakehead, North Dakota and East Texas Systems are in substantial compliance with applicable environmental and safety laws and regulations, the risk of substantial liabilities is inherent in pipeline operations, and the Partnership could incur substantial liabilities. To the extent that the

Partnership is unable to recover environmental costs in its rates (if not recovered through insurance), the Partnership could be subject to material costs.

In general, the Partnership expects to incur future ongoing expenditures to comply with industry and regulatory environment and safety standards. The Partnership does not expect that such expenditures, to the extent they can be estimated, will have a material adverse effect on the Partnership.

Air

The operations of the Partnership are subject to the federal CAA and comparable state statutes. The main impact of these regulations on the Partnership is the requirement to obtain and maintain permit authorizations to operate facilities that emit air contaminants to the atmosphere. These authorizations generally impose emission limits and controls as well as establish monitoring and reporting procedures to demonstrate compliance. Federal and State laws provide varying civil and criminal penalties and liabilities in the case of violations of permit authorizations or in the case of failure to obtain such authorizations. The Partnership is unaware of any significant violations of air quality requirements and expenses of routine compliance with these regulations are not expected to have a material adverse impact on the Partnership.

Water

The federal CWA, as amended, imposes strict controls on the discharge of any pollutant, including oil, into the waters of the United States. The CWA provides penalties for any such discharge, imposes liability for clean-up costs and natural resource damage, and allows for third party lawsuits. As required by the CWA, the Partnership has developed Facility Response Plans, which are designed to prevent contamination of waters in the event of a petroleum overflow, rupture or leak, and has submitted these plans to, and received the approval of, the OPS of the U.S. DOT. The federal Safe Drinking Water Act of 1974, as amended, further regulates discharges into groundwater. State laws also provide varying civil and criminal penalties and liabilities in the case of a release of pollutants into surface water or groundwater. Expenses of routine compliance with these and other similar regulations are not expected to have a material adverse impact on the Partnership.

Remediation Matters

Contamination resulting from spills of crude oil and petroleum products is not unusual within the petroleum pipeline industry. Historic spills along the Lakehead System as a result of past operations may have resulted in soil or groundwater contamination. The Partnership is continuing to address known sites through monitoring and remediation programs. Currently, expenses relating to such remediation programs are not expected to have a material adverse impact on the Partnership.

Superfund

The CERCLA, as amended, also known as "Superfund," and comparable state laws impose liability, without regard to fault or the legality of the original act, on certain classes of persons that contribute to the release of a "hazardous substance" into the environment. In the course of its ordinary operations, the Partnership's systems generate wastes, some of which fall within the federal and state statutory definitions of a "hazardous substance" and some of which were historically disposed of at sites that may require cleanup under Superfund and related state statutes. The Partnership is unaware of any such obligations at this time.

Waste

The Partnership generates hazardous and non-hazardous solid wastes that are subject to requirements of the federal RCRA and comparable state statutes. The Partnership believes that operations of its systems are in substantial compliance with such statutes in all states in which it operates.

Pipeline Safety Legislation and Regulation

The operations of the Lakehead System are subject to construction, operating and safety regulation under the Act as applied by the OPS. Various other federal, state and local legislative and regulatory requirements also affect construction, maintenance and operation practices. The Act has been amended periodically requiring OPS to consider environmental impacts and cost-benefit analysis, in addition to its traditional public safety considerations, when developing pipeline safety regulations. Among the amendments, OPS was mandated to establish pipeline operator qualification rules that were issued in 1999 and which came into effect during 2001. Other requirements include mandating OPS to establish a national pipeline mapping and records system, evaluating the feasibility of requiring additional valves and/or remotely operated valves and completing the identification of areas "unusually environmentally sensitive" to leaks from liquid pipelines. In December 2000, the OPS issued final rules defining "unusually environmentally sensitive areas" and is in the process of identifying and mapping these distinct areas throughout the U.S. As well, in December 2000, OPS issued final rules for "Pipeline Integrity Management in High Consequence Areas". In December 2001, OPS issued final rules for more prescriptive corrosion protection standards, and for more stringent spill reporting requirements for liquid pipelines. These more strigent requirements were generally consistent with existing industry codes and standards. The Partnership has submitted pipeline maps and descriptive detail to OPS as part of its voluntary national mapping and records system and is in the process of enhancing its integrity management program for liquid pipelines to meet the new regulatory requirements. The recently issued rules or proposed rules are comprehensive, but are not expected to have a material adverse financial effect on the Partnership.

In the aftermath of two significant pipeline incidents in Washington and New Mexico during 1999 and 2000, the U.S. Congress has proposed several bills to significantly amend the Act. Proposals include many initiatives already underway by OPS and discussed above. Additional proposals of significance include potential certification of pipeline control operators or qualification programs, more prescriptive integrity management programs, broader public communications, increased involvement of states, strengthened inspection and enforcement authority for OPS, and broader research and development programs. The Partnership expects final legislation to be considered in the first half of 2002. As this legislative initiative is still evolving, the financial impact of additional new legislative requirements cannot be determined at this time.

Employees

Neither the General Partner nor the Partnership has any employees. The General Partner is responsible for the management and operation of the Partnership, and to fulfill these obligations, it has entered into agreements with Enbridge and several of its subsidiaries to provide the necessary services. The Partnership reimburses service providers for expenses incurred in performing these services at cost.

Item 3. Legal Proceedings

The Partnership is a party in a limited number of legal proceedings arising in the ordinary course of business. The Partnership believes that the outcome of these matters will not, individually or in the aggregate, have a material adverse effect on the financial condition of the Partnership.

In September 2001, the Partnership settled its third party claim for costs incurred in connection with a release of crude oil in September 1998 and an NGL release in October 1998, near Plummer, Minnesota. The Partnership recovered an amount that adequately reimbursed it for costs incurred to remediate the releases. There are no further pending legal or regulatory enforcement actions in connection with these releases.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during 2001.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

The Partnership's Class A Common Units are listed and traded on the New York Stock Exchange, the principal market for the Class A Common Units, under the symbol EEP. The quarterly price range per Class A Common Unit and cash distributions paid per unit for 2001 and 2000 are summarized as follows:

	First	Second	Third	Fourth
2001 Quarters				
High	$46.90	$46.50	$49.60	$48.90
Low	$41.25	$43.80	$39.50	$38.90
Cash distributions paid	$0.875	$0.875	$0.875	$0.875
2000 Quarters *				
High	$ 40⅞	$ 40⅛	$ 42¾	$43.49
Low	$ 32	$ 33¼	$ 37⅛	$ 36⅝
Cash distributions paid	$0.875	$0.875	$0.875	$0.875

* In August 2000, the NYSE started trading in cents in lieu of fractions. EEP converted to trading in cents in December 2000.

On February 20, 2002, the last reported sales price of the Class A Common Units on the New York Stock Exchange was $45.30. At February 20, 2002, there were approximately 40,000 Class A Common Unitholders of which there were approximately 2,500 registered Class A Common Unitholders of record. There is no established public trading market for the Partnership's Class B Common Units, all of which are held by the General Partner.

Item 6. Selected Financial Data

The following table sets forth, for the periods and at the dates indicated, summary historical financial and operating data for the Partnership. The table is derived from the consolidated financial statements of the Partnership and notes thereto, and should be read in conjunction with those audited financial statements.

	Year Ended December 31,				
	2001	2000	1999	1998	1997
	(Dollars in Millions, Except Per Unit Amounts)				
Income Statement Data:					
Operating revenue	$ 340.4	$ 305.6	$ 312.6	$ 287.7	$ 282.1
Operating expenses	244.5	189.1	182.3	182.3	174.0
Operating income	95.9	116.5	130.3	105.4	108.1
Interest and other income	2.8	4.8	3.4	6.0	9.7
Interest expense	(59.3)	(60.4)	(54.1)	(21.9)	(38.6)
Minority interest	(0.5)	(0.7)	(0.9)	(1.0)	(0.9)
Net income	$ 38.9	$ 60.2	$ 78.7	$ 88.5	$ 78.3
Net income per unit(1)	$ 0.98	$ 1.78	$ 2.48	$ 3.07	$ 3.02
Cash distributions paid per unit	$ 3.50	$ 3.50	$ 3.485	$ 3.36	$ 2.92
Financial Position Data (at year end):					
Property, plant and equipment, net	$1,486.6	$1,281.9	$1,321.3	$1,296.2	$ 850.3
Total assets	$1,649.2	$1,376.7	$1,413.7	$1,414.4	$1,063.2
Long-term debt	$ 715.4	$ 799.3	$ 784.5	$ 814.5	$ 463.0
Partners' capital					
Class A common unitholders	$ 577.0	$ 488.6	$ 533.1	$ 453.4	$ 461.6
Class B common unitholder	48.8	42.1	47.4	37.3	36.7
General Partner	6.5	5.2	5.6	4.3	3.5
Other comprehensive income	11.9	—	—	—	—
	$ 644.2	$ 535.9	$ 586.1	$ 495.0	$ 501.8
Cash Flow Data:					
Cash flow from operating activities	$ 122.3	$ 117.3	$ 101.6	$ 103.6	$ 106.6
Cash flow used in investing activities	$ (299.1)	$ (20.7)	$ (91.1)	$ (427.9)	$ (101.7)
Cash flow from (used in) financing activities	$ 179.8	$ (99.4)	$ (17.5)	$ 252.7	$ 24.1
Acquisitions and capital expenditures included in investing activities	$ (300.0)	$ (21.7)	$ (82.9)	$ (487.3)	$ (126.9)
Operating Data:					
Barrel miles (billions)	333	341	350	391	389
Deliveries (thousands of bpd)					
United States	960	976	898	992	960
Ontario	355	362	471	570	552
	1,315	1,338	1,369	1,562	1,512

(1) The General Partner's allocation of net income in the following amounts has been deducted before calculating net income per unit: 2001, $9.1 million; 2000, $8.8 million; 1999, $9.1 million; 1998, $8.0 million; and 1997, $4.4 million.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with the audited consolidated financial statements and accompanying notes of the Partnership listed in the Index to Financial Statements on page F-1 of this report. Material period-to-period variances in the consolidated statements of income are discussed under "Results of Operations". The "Liquidity and Capital Resources" section analyzes cash flows and financial position. "Other Matters" addresses future prospects, regulatory matters and recent accounting developments.

General

Historically, and for the majority of 2001, the Partnership had been solely a transporter of crude oil and NGL through its Lakehead System. The Lakehead System forms part of the world's longest liquid petroleum pipeline system that strategically links crude oil production from the Western Canadian Sedimentary Basin to key markets in the U.S. Midwest and eastern Canada. During 2001, crude oil production from western Canada continued to lag behind industry expectations and, as a result, deliveries on the Lakehead System were lower than the previous year. Despite strong crude oil prices, exploration and development activity focused on natural gas drilling rather than crude oil, due to more favorable natural gas prices. Heavy crude oil production was particularly affected due to a combination of an unusually low heavy crude oil price relative to light crude, higher cost of diluents required to be added to heavy crude for transportation and higher costs of natural gas used for fuel in thermal recovery processes. Western Canadian crude oil supply was also adversely affected by production problems and longer than expected maintenance shut-downs at a major Alberta oil sands plant.

The Partnership believes that crude oil production, and therefore deliveries on the Lakehead System, will improve in 2002. Incremental production is anticipated from some of the heavy crude oil sands development projects that are expected to go into service during the year. Furthermore, long-term prospects for increased crude oil production remain positive as western Canadian producers continue to be committed to expansion projects that will bring incremental supply to the Lakehead System. See—"Other Matters,—Future Prospects".

At the end of the fourth quarter of 2001, the Partnership diversified its industry and geographic focus with the purchase of natural gas gathering, treating and processing assets located in east Texas. The Partnership purchased approximately 2,000 miles of gathering pipelines, 37 field compressor stations, four gas treating plants with a capacity of 595 MMcf/d and three gas processing plants with a capacity of 375 MMcf/d. The East Texas System delivers approximately 400,000 Mmbtu/d of natural gas into the northeast portion of Texas and is connected to the Carthage, Texas hub, one of the United States' most active natural gas marketing and trading locations. Through natural gas purchase or transportation contracts, the East Texas System has secured substantial long-term dedications of significant reserves in all the major basins it serves. The Partnership forecasts natural gas supply available to the East Texas System will be between 400,000 and 420,000 Mmbtu/d in 2002.

Recent Acquisitions

The Partnership completed two acquisitions during 2001. Effective May 18, 2001, the Partnership acquired the assets of Enbridge Pipelines (North Dakota) from Enbridge for cash of $35.4 million, which included working capital and transaction costs. The North Dakota assets include 330 miles of crude oil gathering lines connected to a 620 mile trunk line with an operating capacity of 84,000 barrels per day. This system gathers crude oil from the Williston Basin in North Dakota and Montana and receives Canadian crude oil via an interconnect with Enbridge's gathering system in Saskatchewan, Canada, for delivery primarily to the Lakehead System at Clearbrook, Minnesota. The acquisition was funded by a short-term loan from the General Partner.

As noted above, effective November 30, 2001, the Partnership acquired the East Texas Sysytem for a cash purchase price of $230.5 million. The acquisition was partially funded with proceeds from the sale of Class A Common Units in November 2001, and with a short-term loan from the General Partner.

Critical Accounting Policies and Estimates

The Partnership's financial statements have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures. The basis for these estimates is historical experience and various other assumptions that are believed to be reasonable, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from these estimates under different assumptions or conditions.

The Partnership believes the following critical accounting policies affect the more significant judgments and estimates used in the preparation of its consolidated financial statements. In the normal course of the Partnership's business, judgment is involved in determining depreciation, customer and pipeline oil overage balance, crude oil measurement losses and year-end accruals. The Partnership records depreciation based on the estimated useful lives of the assets, which requires various assumptions to be made, including the supply of and demand for hydrocarbons in the markets served by assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. Changes in any of these assumptions may impact the rate at which depreciation is recognized in the financial statements. The oil overage balance is recorded by the Partnership based on measurement estimates. These estimates are based on mathematical calculations, physical measurement and include assumptions related to the type of crude oil, its market value, normal physical losses due to evaporation and capacity limitations of the System. If there is a material change in these assumptions, it may result in a change to the carrying value of the oil overage balance or revision of oil measurement loss estimates. Last, in the normal course of preparing the year-end financial statements, revenue and expense accruals are made for the month of December to ensure amounts are complete and accurate on an annual basis. Judgments and estimates are necessary to prepare these accruals. Changes in these estimates are not expected to have a material impact on the earnings of the Partnership. For additional details relating to the Partnership's accounting policies, see Note 2 to the Partnership's Consolidated Financial Statements.

Results of Operations

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Net income for 2001 was $38.9 million ($0.98 per unit) compared with $60.2 million ($1.78 per unit) for 2000. Net income for 2001 was $21.3 million lower than 2000 primarily due to higher operating expenses, which included a non-recurring charge for costs related to the relocation of the Partnership's head office. Earnings per unit were lower due to reduced net income and a greater number of units outstanding following the issuance of a total of 4,063,634 Class A Common Units during the year. The weighted average number of Common Units outstanding increased from 28.9 million in 2000 to 30.2 million in 2001. The results of operations for 2001 also include the earnings of the North Dakota System from the acquisition date of May 18, 2001. The contribution to net operating income from the North Dakota acquisition was $2.6 million for 2001. The results of operations for 2001 also include the contributions from the East Texas System from the acquisition date of November 30, 2001.

Operating revenue for 2001 was $340.4 million, or $34.8 million higher than 2000. The increase was primarily due to the inclusion of operating revenue from the East Texas System and higher tariffs on the Lakehead System, offset by the impact of a decline in deliveries on the Lakehead System. Deliveries averaged 1.315 million bpd on the Lakehead System in 2001, compared to 1.338 million bpd in 2000. This decline occurred due to lower crude oil production in western Canada. System utilization on the Lakehead System, measured in barrel miles, was 333 billion for 2001, compared to 341 billion for 2000, reflecting the decline in deliveries. The average haul, measured in miles, was 694 for 2001, compared to 696 in 2000.

Total operating expenses of $244.5 million in 2001 were higher than the 2000 level of $189.1 million, due to the inclusion of the cost of natural gas associated with the East Texas System ($26.3 million), higher operating and administrative costs ($23.9 million), depreciation expense ($2.7 million) and power costs ($2.5 million). Operating and administrative expenses increased $23.9 million primarily due to higher oil measurement losses and costs related to the relocation of the Partnership's head office.

Oil measurement losses occur as part of normal operating conditions of a liquid petroleum pipeline and can be classified as follows:

- Physical losses—occur through evaporation, shrinkage, difference in measurement between receipt and delivery locations and other incidents;
- Degradation losses—result from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil in the pipeline; and
- Revaluation losses—are a function of the price of crude oil, the level of carrier's inventory and inventory positions of customers.

Oil measurement losses were approximately $18.0 million in 2001, or approximately $11.0 million higher than in 2000. This increase was primarily due to higher differentials between light and heavy crude oil prices, which increased the expense associated with inherent degradation between the batches of crude oil in the pipeline system. Also included in oil measurement losses was an adjustment to the value of the oil overage balance of approximately $5.0 million. This was the result of refinements in the oil measurement loss estimation process, as well as improvements in the accuracy of measuring oil losses through the development of new software applications.

During the second quarter of 2001, the Partnership announced the closing of its head office in Duluth, Minnesota and its relocation to Houston, Texas. The results of operations for 2001 include a charge of $5.0 million related to the expense of relocating the office.

Interest expense of $59.3 million in 2001 was $1.1 million lower than 2000 primarily due to a combination of lower average debt balances and interest rates on the revolving credit facility.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Net income for 2000 was $60.2 million ($1.78 per unit) compared with $78.7 million ($2.48 per unit) for 1999. Net income for 2000 was $18.5 million lower than 1999 primarily due to lower pipeline utilization and increased operating costs. The decline in utilization was a result of low crude oil prices in late 1998 and early 1999, which caused crude oil producers to limit their investment in oil producing facilities. Coupled with natural declines of crude oil reserves, reduced investment by oil producers adversely affected short-term Partnership results due to lower volumes of crude oil being available for transport.

Operating revenue for 2000 was $305.6 million, or $7.0 million less than 1999. The decrease was primarily due to the decline in deliveries. Deliveries averaged 1.338 million bpd in 2000, compared to 1.369 million bpd in 1999. The decline occurred because the supply of crude oil had not recovered to anticipated levels, further exacerbated by the effects of crude oil producer maintenance shutdowns and wetter than normal weather in western Canada, which delayed oil well tie-ins and other development activities. System utilization, measured in barrel miles, was 341 billion for 2000, compared to 350 billion for 1999, reflecting the decline in deliveries. Average haul was 696 miles in 2000, compared to 700 miles in 1999.

Total operating expenses of $189.1 million in 2000 were higher than 1999 levels of $182.3 million as higher operating and administrative costs and higher depreciation expense associated with expansions of the Lakehead System were partially offset by lower power costs. Power costs decreased $5.6 million due to lower throughput volumes. Operating and administrative expense increased $9.1 million primarily due to higher oil measurement losses, higher property taxes associated with recent expansion projects and lower capitalized charges due to the decrease of construction activity in 2000. Oil measurement losses were approximately $3.9 million higher in 2000 compared to 1999, primarily due to the higher differentials between the light and heavy crude oil prices. Depreciation expense increased $3.3 million primarily due to the full year impact of placing the Terrace Phase I project in service on April 1, 1999 and plant additions from the prior year.

Interest expense of $60.4 million in 2000 was $6.3 million higher than 1999 primarily due to lower capitalized interest resulting from less construction activity during 2000.

Liquidity and Capital Resources

The primary cash requirements for the Partnership consist of normal operating expenses, maintenance and expansion capital expenditures, debt service payments, distributions to the partners and acquisitions of new businesses. Short-term cash requirements, such as operating expenses, maintenance capital expenditures and quarterly distributions to the partners are expected to be funded by operating cash flows. During 2001, working capital decreased by $219.9 million to ($171.3) million due to the short-term loans from the General Partner to fund the acquisitions of the North Dakota System and the East Texas System. On an ongoing basis, the Partnership intends to refinance these loans with long-term debt or to repay them with proceeds from equity issuances, which are not expected to impact the Partnership's ability to fund short-term operations.

At December 31, 2001, cash and cash equivalents totaled $40.2 million, up $3.0 million from December 31, 2000. Of this amount, $31.8 million ($0.90 per unit) was used for the cash distribution paid to unitholders on February 14, 2002, with the remaining $8.4 million available for future cash distributions, capital expenditures and other business needs.

Cash flows from operating activities for 2001 were $122.3 million, compared to $117.3 million for 2000. Cash flows from operating activities primarily reflect the effects of net income, depreciation and amortization, and changes in working capital. Net income decreased primarily due to higher operating expenses. The change in operating assets and liabilites was $24.6 million higher in 2001, primarily due to the change in the oil overage balance.

Cash outflows used in investing activities were $299.1 million in 2001, compared to $20.7 million in 2000. In May 2001, the Partnership paid $35.4 million to Enbridge for the North Dakota System. In November 2001, $229.6 million (net of cash acquired) was paid to purchase the East Texas System. For additional information regarding the acquisitions of the North Dakota and East Texas Systems, see Note 3 to the Partnership's Consolidated Financial Statements.

In 2001, the Partnership made capital expenditures (excluding acquisitions) of $35.0 million, of which $9.4 million was for pipeline system enhancements, $9.3 million for core maintenance activities and $16.3 million for Terrace. In 2000, the Partnership made capital expenditures of $21.7 million, of which $10.8 million was for pipeline enhancements and $10.9 million for core maintenance activities.

In 2002, the Partnership anticipates spending approximately $14.0 million for routine pipeline system enhancements, $15.0 million for core maintenance activities, and $194.0 million for Terrace. Excluding major expansion projects, ongoing capital expenditures are expected to average approximately $30.0 million annually (approximately 50% for core maintenance and 50% for enhancement of the pipeline system). Core maintenance activities, such as the replacement of equipment and preventive maintenance programs, will be undertaken to enable the Partnership's pipeline systems to continue to operate at their maximum operating capacity. Enhancements to the pipeline systems, such as renewal and replacement of pipe, are expected to extend the life of the systems and permit the Partnership to respond to developing industry and government standards and the changing service expectations of its customers.

On an annual basis, the Partnership makes expenditures of a capital and operating nature related to maintaining compliance of its transportation systems with applicable environmental and safety regulations. Capital expenditures for safety and environmental purposes comprise a portion of the routine core maintenance and enhancement capital expenditures annually incurred by the Partnership. Amounts are not readily segregated since individual projects may be undertaken for a variety of reasons in addition to environment and safety considerations. Based on existing laws and regulations, future environmental and safety expenditures are not anticipated to have a material adverse impact on the Partnership's results of operations.

Cash flows from financing activities were $179.8 million in 2001 compared to ($99.4) million in 2000. These cash flows are affected primarily by proceeds of unit issuances, fixed rate financing, distributions to the partners, repayments of variable rate financing, and borrowings from affiliates. During 2001, the acquisitions of the North Dakota and East Texas Systems were financed through a combination of proceeds from unit issuances and short-term loans from the General Partner. In January 2002, these loans were refinanced with a subordinated loan payable to the General Partner which matures in January 2007. This loan bears interest at a floating market based rate and the Partnership has the right to repay the principal amount of this loan plus accrued interest at any time, without penalty.

At December 31, 2001, the Partnership had outstanding $310.0 million aggregate principal amount of First Mortgage Notes bearing interest at the rate of 9.15% per annum, payable semi-annually. The notes are due and payable in ten equal annual installments beginning in December 2002, and are expected to be funded by operating cash flows or refinancing arrangements. The Partnership had a $350.0 million Revolving Credit Facility under which $137.0 million was outstanding at December 31, 2001. Interest rates on amounts drawn under this facility were variable and averaged 5.3% in 2001.

On January 29, 2002, the Partnership established two new unsecured credit facilities, a $300.0 million three-year term facility and a $300.0 million 364-Day facility, to replace the existing $350.0 million Revolving Credit Facility. Under the terms of these new facilities, the Partnership and the Operating Partnership may borrow funds up to a combined maximum of $300.0 million under the three-year term facility and a combined maximum of $300.0 million under the 364-Day Facility. In addition, when no default exists, the Partnership may designate any of its subsidiaries that is a material subsidiary to borrow under either or both the facilities and subject to complying with certain administrative procedures, it will be permitted to borrow. Any borrowings under either facility will be guaranteed by the Partnership, the Operating Partnership and any of its material subsidiaries, unless it is the borrower. Upon closing, indebtedness under the $350.0 million Revolving Credit Facility was refinanced with indebtedness drawn under the new credit facilities and the $350.0 million Revolving Credit Facility was terminated. As at February 20, 2002, the Partnership and the Operating Partnership had borrowed approximately $194.0 million under the two new credit facilities.

The Partnership completed two Class A Common Unit issuances during 2001. On May 22, 2001, the Partnership issued approximately 1.7 million Class A Common Units at $45.75 per unit. The net proceeds from the offering were approximately $77.0 million and were used to repay indebtedness under the Partnership's Revolving Credit Facility incurred to finance expansions of its liquids pipeline system. On June 4, 2001, 64,999 Class A Common Units were issued in connection with the underwriter's exercise of the over-allotment option granted in connection with the issuance on May 22, 2001. Net proceeds from the units issued from the over-allotment totaled $2.9 million. On November 26, 2001, the Partnership issued 2.25 million Class A Common Units at $42.20 per unit, for net proceeds of $91.4 million. Net proceeds from the offering were used to fund a portion of the acquisition of the East Texas System. These offerings increased the number of Class A Common Units outstanding to 29,053,634 as of December 31, 2001.

The Partnership has on file a $500 million shelf registration statement (the "Registration Statement") with the SEC for the issuance of additional Class A Common Units. The purpose of the Registration Statement is to give the Partnership flexibility to respond quickly to attractive financing opportunities in the capital markets as it pursues its growth strategy and manages its debt obligations. As of December 31, 2001, approximately $405 million in Class A Common Units remained available for issuance under the Registration Statement.

In November 2000, the Operating Partnership sold $100 million of 7.9% senior notes due 2012. The proceeds from this sale were used to retire bank debt. In 1998, the Operating Partnership sold $100 million of 7% senior notes due 2018 and $100 million of 7.125% senior notes due 2028. For additional details relating to the Partnership's debt, see Note 8 to the Partnership's Consolidated Financial Statements.

The Partnership distributes quarterly all of its Available Cash, which generally is defined to mean for any calendar quarter the sum of all of the cash receipts of the Partnership plus net reductions to reserves less all of its cash disbursements and net additions to reserves. These reserves are retained to provide for the proper conduct of the Partnership's business, to stabilize distributions of cash to unitholders and the General Partner and, as necessary, to comply with the terms of any agreement or obligation of the Partnership. On February 14, 2002, the Partnership paid a $0.90 per unit distribution for the fourth quarter of 2001.

The Partnership anticipates that it will continue to have adequate liquidity to fund future recurring operating and investing activities. The Partnership intends to fund ongoing capital expenditures with the proceeds from future debt and equity offerings, other borrowings, cash generated from operating activities, and existing cash and cash equivalents. Cash distributions are expected to be funded with internally generated cash. The Partnership's ability to complete future debt and equity offerings will depend on prevailing market conditions and the then existing financial condition of the Partnership.

Other Matters

Future Prospects

The primary strategy of the Partnership is to grow cash distributions through the profitable expansion of the Lakehead System and through development and acquisition of complementary businesses with a similar risk profile to the Partnership's current crude oil and natural gas liquids transportation business. If the risk profiles of these acquisitions are higher, the Partnership intends to mitigate these risks through the use of financial instruments to achieve an acceptable risk profile.

The System serves as a strategic link between the western Canadian oil fields and the markets of the Upper Midwest United States and eastern Canada. In response to market conditions, the Partnership plans to maintain the service capability of the Lakehead System and to expand its capacity and improve efficiency where appropriate. To the extent allowed under orders of FERC or by agreement with customers, the Partnership expects to file additional tariff increases and surcharges from time to time to reflect these ongoing expansions.

Terrace Expansion Program

The Partnership and Enbridge are undertaking a major expansion of the entire System, including the Lakehead System. This expansion is referred to as the Terrace expansion program. This expansion program consists of a multi-phase expansion of both the U.S. and Canadian portions of the System. Upon the completion of all three phases of Terrace, the Partnership expects that approximately 350,000 barrels per day of capacity will be added to the System.

- Phase I of Terrace was completed in 1999 and included construction of new 36-inch diameter pipeline facilities from Kerrobert, Saskatchewan to Clearbrook, Minnesota that added approximately 170,000 barrels per day of capacity to the System. The Partnership's share of the cost of Phase I was approximately $140 million.
- Construction of Phase II of Terrace began in June 2001, and was placed in service in early 2002. While Phase II did not involve construction on the Lakehead System, the approximate 40,000 barrel per day increase in capacity of the Enbridge System is expected to benefit the Lakehead System directly as additional deliveries begin from the Alberta oil sands.
- Phase III of Terrace is designed primarily to increase heavy oil transportation capacity on the Lakehead System between Clearbrook, Minnesota and Superior, Wisconsin by approximately 140,000 barrels per day. CAPP provided notice in June 2001 to proceed with this phase. Following permitting approval, construction on this phase of the program began in late 2001. The estimated cost to the Partnership of Terrace Phase III is approximately $210 million, and the new facilities are expected to be in service in 2003.
- CAPP also has provided notification requesting additional pipeline facilities to enhance market access to PADD 2. The project is part of the future phases portion of Terrace. The estimated cost of this project is approximately $35 million and, subject to final approvals, is expected to be in service in 2003.

Under a tariff agreement approved by the FERC in 1999, the Partnership implemented a tariff surcharge for Terrace of approximately $0.013 per barrel (for light crude oil from the Canadian border to Chicago). On April 1, 2001, the surcharge was increased to $0.026 per barrel. Subject to any adjustments permitted under the Tariff Agreement, this toll will be effective until April 1, 2004, when, absent any agreement from Enbridge stating otherwise, the toll will change to $0.007 per barrel to the Partnership. This new toll will be in effect for the next six years, after which time it will return to $0.013 per barrel for the Partnership. The tariff surcharge is based on the completion of all three phases of Terrace.

Prospects for Growth in the Supply of Western Canadian Crude Oil

Changes in supply from western Canada directly affect movements on the Enbridge System and, therefore, the supply available for transportation on the Lakehead System. Enbridge regularly updates its forecast of western Canadian crude oil supply. This is a long-term outlook, which incorporates updated supply projections from producers of both conventional and non-conventional sources of crude oil. The forecast includes supply from existing operations, proposed expansions of existing operations and production from selected projects proposed for development.

The forecast developed by Enbridge in early 2002 projects that the supply of western Canadian crude oil will be approximately 2.1 million bpd in 2002, 2.2 million bpd in 2003 and approximately 2.3 million bpd in 2004. By 2011, supply is expected to increase to approximately 2.8 million bpd. In 2001, the Enbridge System transported approximately 65% of the total western Canadian crude oil production, of which approximately 90% was transported by the Lakehead System. The forecast quantity of crude oil was made subject to numerous uncertainties and assumptions, including a crude oil price ranging from $23 to $26 per barrel from 2002 to 2011. On February 20, 2002, the benchmark West Texas Intermediate crude oil price closed at $20.29 per barrel.

The Partnership believes that the outlook for increased crude oil production in western Canada continues to be positive, as evidenced by the recently completed Enbridge forecast and CAPP's request to proceed with Phase III of Terrace. The timing of this growth in the supply of western Canadian crude oil, however, will depend on the level of crude oil prices and drilling activity, and the timing of completion of projects to produce heavy and synthetic oil from the Alberta oil sands. During the last quarter of 2001, volumes were starting to improve as one of the Alberta oil sands expansion projects was placed into service. These volumes are expected to continue to increase during 2002. As a result, based on a recent survey of shippers, the Partnership anticipates that deliveries on the Lakehead System will average approximately 1.33 to 1.40 million bpd per day during 2002.

In the near-term, management believes that the Partnership is well positioned to benefit from the expected increases in western Canadian crude oil supply through utilization of a combination of existing capacity and expansions currently underway. Canada has substantial reserves of non-conventional hydrocarbon resources consisting predominantly of the Alberta oil sands. Firms involved in the production of heavy and synthetic crude oil from the oil sands region of western Canada have announced expansion projects over the next ten years with value in excess of Cdn. $40.0 billion and representing more than two million barrels per day of potential incremental production. Alberta oil sands projects are expected to provide substantial increases in the production of heavy and synthetic crude oil in western Canada well into the future.

Growth Beyond the Lakehead System

Diversification of the energy transportation business through the development of complementary businesses and through acquisitions is a key objective of the Partnership's strategic plan. Business development efforts will focus on crude oil and refined products pipelines, natural gas systems, terminals and related facilities with a risk profile similar to that of the Lakehead System. The Partnership expects such assets will become available with the continuing trend of rationalization of the energy infrastructure in the United States, as existing owners focus on core aspects of their businesses and improve upon their financial position. Management believes that the Partnership is well positioned to participate in these opportunities, as it is an established, low-cost operator with a strong track record of reliability.

The Partnership intends to expand beyond the market currently served in PADD 2 by seeking out new opportunities throughout the U.S., particularly in the U.S. Gulf Coast area. The Partnership intends to actively pursue opportunities to provide terminal and logistics solutions to the major crude oil and natural gas producers. The North Dakota System and East Texas System acquisitions represent the Partnership's initial steps to implement this diversification strategy.

The Partnership relocated its head office from Duluth, Minnesota to Houston, Texas during the last half of 2001. This relocation occurred due to the Enbridge purchase of Midcoast, a then publicly traded Houston-based natural gas gathering, transportation and processing company. As a result of this purchase, the business development team of Midcoast will provide support to the growth strategy of the Partnership. This team has an established track record of profitable growth and experience with emerging Mid-continent and Gulf Coast transportation opportunities.

Regulatory Matters

The Lakehead and North Dakota Systems are subject to a rate regulatory methodology that prescribes rate ceilings that are adjusted each July 1. The rate ceilings are adjusted by reference to annual changes in the Producer Price Index for Finished Goods minus 1 percent. The General Partner expects the rate ceiling to increase slightly for 2002. This increase in the PPIFG-1 should not have a material effect on 2002 operating revenue since the increase will not be effective until mid-year 2002 and does not apply to SEP II or Terrace.

The 1996 Settlement Agreement among the Partnership, CAPP and ADOE provided that the agreed underlying tariff rates on the Lakehead System would be subject to indexing as prescribed by FERC regulation and that CAPP and ADOE would not challenge any rates within the indexed ceiling until after October 2001. To challenge the rates, FERC regulations require that a shipper must show that the amount of any indexed rate increase is so substantially in excess of the pipeline's increase in costs as to be unjust and unreasonable. The Partnership believes that changes in costs, other than those associated with expansions and oil losses, have been in line with changes in the index, and does not expect a challenge. The Partnership strives to have a strong working relationship with its shippers.

The indexed rate environment, the Settlement Agreement, and other negotiated settlements with customers for SEP II and Terrace have benefited the Partnership and its customers by restoring stability and providing predictable tariff rates. To the extent allowed under FERC orders or by agreement with customers, the Partnership has filed, and will continue to file, for additional tariff increases from time to time to reflect ongoing expansion programs.

The East Texas System is subject to the regulatory oversight of the Texas Railroad Commission with respect to the intrastate pipeline facilities and to a lesser extent, the FERC, with respect to deliveries into interstate commerce. The non-pipeline aspects of the East Texas System are not subject to commercial regulatory oversight.

Recent Accounting Developments

In June 1998, the FASB issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." This Statement requires that all derivatives be recognized at fair value in the balance sheet and all changes in fair value be recognized currently in earnings or deferred as a component of other comprehensive income, depending on the intended use of the derivative. The Partnership adopted SFAS No. 133 on January 1, 2001.

In June 2001, the FASB issued SFAS No. 141, "Business Combinations." This Statement requires the use of the purchase method for all business combinations. In addition, it requires the reassessment of intangible assets to determine if they are appropriately classified either separately or within goodwill. This Statement is effective for business combinations initiated after June 30, 2001. The Partnership adopted SFAS No. 141 on July 1, 2001 with no impact on results of operations, financial position or cash flows.

In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets". Under SFAS No. 142, goodwill and intangible assets with indefinite lives will not be amortized but will be reviewed for impairment at least annually. Intangible assets with finite lives will continue to be amortized over their useful lives, which will not be limited to a maximum life of forty years. The Partnership adopted SFAS No. 142 on January 1, 2002. This standard is not expected to have a material impact on results of operations, financial position or cash flows.

Also in July 2001, the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations" under which retirement obligations will be recognized at fair value in the period they are incurred. When the liability is initially recorded, the cost is capitalized by increasing the asset's carrying value, which is subsequently depreciated over its useful life. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. The Partnership is currently evaluating the potential effects of adopting SFAS No. 143, if any, on its financial condition and results of operations as well as the timing of its adoption.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". SFAS No. 144 clarifies the financial accounting and reporting to be recognized if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows. The impairment loss to be recognized is the difference between the carrying amount and the fair value of the assets. The Partnership adopted SFAS No. 144 on January 1, 2002. This standard is not expected to have a material impact on results of operations, financial position or cash flows.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate and Foreign Exchange Risk

To the extent the amounts drawn under its revolving credit facilities carry a floating rate of interest, the Partnership's earnings and cash flow are exposed to changes in interest rates. This exposure is managed through periodically refinancing floating rate bank debt with long-term fixed rate debt and through the use of interest rate risk management agreements. The Partnership does not have any material exposure to movements in foreign exchange rates as virtually all of its revenue and expense is denominated in US dollars. To the extent that a material foreign exchange exposure were to arise, the Partnership intends to hedge such exposure using forward or other derivative contracts.

The table below summarizes the Partnership's derivative financial instruments and other financial instruments that are sensitive to changes in interest rates, including interest rate swaps and debt obligations. For debt obligations, the table presents principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the table presents notional amounts and weighted average interest rates by expected (contractual) maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract.

	Expected Maturity Date							
December 31, 2001	**2002**	**2003**	**2004**	**2005**	**2006**	**There-After**	**Total**	**Fair Value**
				($U.S. in Millions)				
Liabilities								
Fixed Rate:								
First Mortgage Notes	$31.0	$31.0	$31.0	$ 31.0	$ 31.0	$155.0	$310.0	$342.6
Interest Rate	9.15%	9.15%	9.15%	9.15%	9.15%	9.15%	—	—
Senior Unsecured Notes	$ 0	$ 0	$ 0	$ 0	$ 0	$300.0	$300.0	$291.4
Average Interest Rate	—	—	—	—	—	7.34%	—	—
Variable Rate:								
Revolving Credit Facility	$ 0	$ 0	$ 0	$137.0	$ 0	$ 0	$137.0	$137.0
Weighted Average Interest Rate	—	—	—	2.43%	—	—	—	—
Interest Rate Derivatives								
Interest Rate Swaps:								
Variable to Fixed	$50.0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 50.0	$ (1.9)
Average Pay Rate	6.23%	—	—	—	—	—	—	—

The fair value of the First Mortgage Notes and Senior Unsecured Notes at December 31, 2001, was $342.6 million (2000—$346.5 million) and $291.4 million (2000—$290.3 million), respectively. The Partnership had $137.0 million (2000—$190.0 million) of variable rate debt outstanding under the Revolving Credit Facility at December 31, 2001, with a fair value of $137.0 million (2000—$190.0 million), at an interest rate of 2.43% (2000—6.2%). The Partnership intends to roll over variable rate debt under its revolving credit facilities as the debt matures.

The fair value of the interest rate swap agreements at December 31, 2001 was ($1.9) million (2000—($0.1) million). For additional information concerning the Partnership's debt obligations, please see Note 8 to the Partnership's Consolidated Financial Statements.

Commodity Price Risk

The Partnership's earnings and cash flows associated with the Lakehead System are not materially impacted by changes in commodity prices, as the Partnership does not own the crude oil and NGL it transports. However, commodity prices have a significant impact on the underlying supply of and demand for crude oil and NGL that the Partnership transports. With the Partnership's acquisition of the East Texas System on November 30, 2001, a portion of the Partnership's earnings and cash flows are exposed to movements in the prices of natural gas and NGLs. The Partnership has entered into hedge transactions to substantially mitigate exposure to movements in these prices. The Partnership does not enter into derivative instruments for speculative purposes.

The table below summarizes the Partnership's outstanding derivative financial instruments used to hedge exposure to movements in commodity prices.

	Expected Maturity Date							
December 31, 2001	**2002**	**2003**	**2004**	**2005**	**2006**	**There-After**	**Total**	**Fair Value**
								($U.S. in Millions)
Commodity Hedges								
Natural Gas Liquids (bbls/d)	4,100	0	0	0	0	0	4,100	$ 0.6
Natural Gas (MMBtu/d)	43,000	9,000	9,000	9,000	9,000	45,000	105,000	$13.2

The fair value of the commodity hedging contracts at December 31, 2001 was $13.8 million. No such contracts were outstanding at December 31, 2000.

Item 8. Financial Statements and Supplementary Data

The consolidated financial statements of the Partnership, together with the notes thereto and the independent accountants' report thereon, and unaudited supplementary information, appear on pages F-2 through F-20 of this Report, and are incorporated by reference. Reference should be made to the Index to Financial Statements, Supplementary Information and Financial Statement Schedules on page F-1 of this Report.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

(a) Directors and Executive Officers of the Registrant

The Registrant is a limited partnership and has no officers, directors or employees. Set forth below is certain information concerning the directors and executive officers of the General Partner. Enbridge Pipelines, the sole stockholder of the General Partner, elects the directors of the General Partner on an annual basis. All officers of the General Partner serve at the discretion of the directors of the General Partner.

Name	Age	Position with General Partner
J.R. Bird	52	Director
P.D. Daniel	55	Director
E.C. Hambrook	64	Director
G.K. Petty	60	Director
C.A. Russell	68	Director
D.P. Truswell	58	Director
D.C. Tutcher	53	President and Director
L.H. DeBriyn	55	Vice President
G.L.Sevick	46	Vice President—Operations
M.A. Maki	37	Controller
A. Monaco	42	Treasurer
J.L. Balko	36	Chief Accountant
E.C. Kaitson	45	Corporate Secretary

Mr. Bird was elected Director of the General Partner in September 2000 and served as President from September 2000 until June 2001. Mr. Bird previously served as Treasurer of the General Partner from October 1996 through October 1997. He has also served as Group Vice President, Transportation of Enbridge and President of Enbridge Pipelines since September 2000. Prior to that time he served as Senior Vice President, Corporate Planning and Development of Enbridge from August 1997 through August 2000 and as Vice President and Treasurer of Enbridge from January 1995 to August 1997.

Mr. Daniel was elected a Director of the General Partner in July 1996 and served as its President from July 1996 through October 1997. Mr. Daniel has served as President of Enbridge since September 2000 and as Chief Executive Officer of Enbridge since January 2001. Prior to that time Mr. Daniel also served as President and Chief Operating Officer—Energy Delivery of Enbridge from June 1998 to December 2000. Prior to that time Mr. Daniel served as Executive Vice President and Chief Operating Officer—Energy Transportation Services of Enbridge from September 1997 through June 1998, as Senior Vice President of Enbridge from May 1994 to August 1997, as President and Chief Executive Officer of Enbridge Pipelines from August 1996 to August 1997, and as President and Chief Operating Officer of Enbridge Pipelines from May 1994 to August 1996.

Mr. Hambrook was elected Director of the General Partner in January 1992 and served as Chairman of the General Partner from July 1996 until July 1999. He also serves on the Audit, Finance & Risk Committee pursuant to the over-ride allowed by Rule 303 of the NYSE Company manual. Mr. Hambrook is the President of Hambrook Resources Inc., a real estate investment, marketing and sales company. The NYSE requires that members of the General Partner's audit committee be "independent", which is defined as the absence of any relationship to the Partnership that may interfere with the exercise of his independence from management of the Partnership. The NYSE Company Manual further provides that a director who is an employee (including non-employee executive officers) of the General Partner or any of its affiliates may not serve on the audit committee until three years following the termination of his or her employment, except that one non-independent member is permitted under certain circumstances. Although Mr. Hambrook has never been employed by the General Partner or any of its affiliates, prior to July 15, 1999 he served as Chairman of the Board of the General Partner. The Board of Directors of the General Partner believes that such prior service has not and will not interfere with Mr. Hambrook's exercise of his independence from management of the General Partner.

Mr. Petty was elected Director of the General Partner on February 22, 2001 and serves on the Audit, Finance & Risk Committee. Mr. Petty has served as Director of Enbridge Inc. since January 2001 and as Director of CAE Incorporated since August 1996. Mr. Petty served as President and Chief Executive Officer of Telus Corporation, a Canadian telecommunications company, from November 1994 to November 1999. Mr. Petty is a business consultant providing executive management consulting services to the telecommunications industry.

Mr. Russell was elected Director of the General Partner in October 1985 and serves as the Chairman of the Audit, Finance & Risk Committee. Mr. Russell served as Chairman and Chief Executive Officer of Norwest Bank Minnesota North, N.A. (now known as "Wells Fargo Bank"), from January through December 1995. He also served as a Director of Minnesota Power and Light Co. (now known as "Allete") until May 1996. Other than in his service as Director of the General Partner, Mr. Russell is retired

Mr. Truswell was elected Director of the General Partner in 1991. Since September 2000, Mr. Truswell has served as Group Vice President and Chief Financial Officer of Enbridge and from May 1994 through August 2000 served as Senior Vice President and Chief Financial Officer of Enbridge.

Mr. Tutcher was elected Director and was appointed President of the General Partner in June 2001. He also currently serves as Group Vice President, Transportation Group South, of Enbridge Inc., as well as President of Enbridge Midcoast Energy Inc. He was previously Chairman of the Board, President and Chief Executive Officer of Midcoast Energy Resources, Inc. from its formation in 1992 until its merger with Enbridge on May 15, 2001.

Mr. DeBriyn was elected Vice President, Special Projects of the General Partner in June 2001 and served as Vice President and Director from July 1999 until June 2001. Prior to that time he served as Vice President, Canadian Operations, of Enbridge Pipelines from July 1996 to July 1999, and prior to that time in managerial positions in operations with Enbridge Pipelines and the General Partner.

Mr. Sevick was elected Vice President, Operations of the General Partner in June 2001. Prior to that time, he served as Vice President, Canadian Operations for Enbridge Pipelines from 1999 to June 2001. Prior to that time, he served as Vice President, Engineering & Logistics of Enbridge Consumers Gas from 1998 to 1999 and Senior Vice President, Distribution Operations of Enbridge Consumers Gas from 1996 to 1998.

Mr. Maki was elected Controller of the General Partner in June 2001. Prior to that time he served as Controller, Enbridge Pipelines since September 1999. Prior to that time, he served as Chief Accountant of the General Partner from June 1997 to August 1999.

Mr. Monaco was elected Treasurer of the General Partner in February, 2002. He currently serves as Vice President, Financial Services of Enbridge and prior to that time as Director, Financial Services since 2000. Prior to that time, he served as Director Investor Relations since 1997.

Ms. Balko has served as Chief Accountant since October 1999. Prior to that time, she served in supervisory positions in accounting with Enbridge Pipelines since January 1998, and was with The Westaim Corporation, an investor in, and manufacturer of, industrial technologies in various industries, including the biomedical and semiconductor industries, from November 1995 to December 1997.

Mr. Kaitson has served as Corporate Secretary of the General Partner since November 2001. He also currently serves as Associate General Counsel, Transportation Group South, of Enbridge Inc. He was previously Assistant Corporate Secretary and General Counsel of Midcoast Energy Resources, Inc. from 1997 until its merger with Enbridge on May 15, 2001.

Item 11. Executive Compensation

The General Partner is responsible for the management and operation of the Partnership. The Partnership does not directly employ any of the persons responsible for managing or operating the Partnership's operations, but instead reimburses the General Partner or its affiliates for the services of such persons. The General Partner, in turn, because it has no employees, has entered into services agreements with Enbridge U.S. and other affiliates to provide the services required by the Partnership.

Item 12. Security Ownership of Certain Beneficial Owners and Management

(a) Security Ownership of Certain Beneficial Owners

The following table sets forth information as of the February 20, 2002, with respect to persons known to the Partnership to be the beneficial owners of more than 5% of either class of the Partnership's Units:

Name and Address of Beneficial Owner	Title of Class	Amount and Nature of Beneficial Ownership	Percent Of Class
Enbridge Energy Company, Inc. 1100 Lousisana, Suite 3300 Houston, TX 77002	Class B Common Units	3,912,750	100.0
Goldman, Sachs & Co. The Goldman Sachs Group, Inc. 85 Broad St. New York, N.Y. 10004	Class A Common Units	2,413,517(1)	8.3

(1) Goldman, Sachs & Co. and The Goldman Sachs Group, Inc. reported shared voting and dispositive power with respects to all of such shares in its report on Schedule 13G/A filed February 14, 2002. Each disclaims beneficial ownership.

(b) Security Ownership of Management

The following table sets forth information as of February 20, 2002, with respect to each class of the Partnership's units beneficially owned by executive officers, directors and nominees for director of the General Partner and by all officers, directors and nominees for director of the Partnership as a group:

Name	Title of Class	Amount and Nature of Beneficial Ownership(1)	Percent Of Class
E.C. Hambrook	Class A Common Units	1,000	*
G.K. Petty	Class A Common Units	1,000	*
D.C. Tutcher	Class A Common Units	20,200	*
All Officers, directors and nominees as a group (13 persons)	Class A Common Units	22,200	*

* Less than 1%

(1) Each beneficial owner has sole voting and investment power.

Item 13. Certain Relationships and Related Transactions

The Partnership is managed by the General Partner under the Amended and Restated Agreements of Limited Partnership of the Partnership and the Operating Partnership, as amended. The General Partner has entered into a service agreement with Enbridge U.S., dated January 1, 1996, whereby the General Partner will utilize the resources of Enbridge U.S. to operate the Partnership. Under this agreement, Enbridge U.S. will be reimbursed at cost for all direct and indirect expenses it incurs or payments it makes on behalf of the Partnership. The General Partner also receives certain administrative, engineering, treasury and computer services from Enbridge and Enbridge Pipelines for the benefit of the Partnership. The Partnership reimburses the General Partner for the cost of these services. For information about reimbursements to the General Partner, see Note 9 to the Partnership's Consolidated Financial Statements.

The Partnership has entered into an Agency Agreement dated March 3, 2000 with Tidal Energy Marketing Inc., a joint venture owned 50% by Enbridge, for a term of five years. For a fee and a share of the lease payments in excess of a specified base lease rate, Tidal has agreed to serve as leasing agent for the Partnership's crude oil storage tanks at its Hartsdale facility in Schererville, Indiana. See Note 9 to the Partnership's Consolidated Financial Statements.

The Partnership has entered into an easement acquisition agreement dated October 20, 1997 with Enbridge Mustang, a subsidiary of Enbridge U.S. Pursuant to this agreement, using funds advanced by the Partnership, Enbridge Mustang acquired properties for the purpose of granting a pipeline easement to the Partnership to allow construction of SEP II. Enbridge Mustang is in the process of reselling these properties. As each parcel is resold, Enbridge Mustang retains an easement for transfer to the Partnership and repays the Partnership for the funds advanced to make the original purchase of the property (less the cost of the easement). Enbridge Mustang is being reimbursed for all costs associated with this process at cost by the Partnership and will be indemnified by the Partnership from and against all liabilities that may arise in connection with this process. See Note 9 to the Partnership's Consolidated Financial Statements.

The Partnership has entered into an agreement, dated March 3, 1998, with Mustang and Mobil to provide for a joint tariff covering shipments of western Canadian crude oil to the Patoka pipeline hub south of Chicago. Mustang is a Delaware general partnership owned by Mobil Illinois Pipe Line Company and Enbridge Mustang. Shipments covered by the joint tariff travel on the Lakehead System to Chicago and to the Patoka pipeline hub through the Mustang pipeline system. The joint tariff agreement provides for lower transportation costs to shippers desiring access to the Patoka market area, an incentive which the Partnership believes complements its expansion programs.

The General Partner believes that the terms of the agreements described in the preceding four paragraphs are at least as favorable as terms that could have been obtained from unaffiliated third parties.

For a discussion of distribution restrictions and incentive distributions payable to the General Partner, see Note 4 to the Partnership's Consolidated Financial Statements.

In May 2001, the Partnership acquired the North Dakota System from Enbridge. The assets consist of a 950-mile crude oil pipeline system with capacity of 84,000 bpd, which transports crude oil from Montana, North Dakota and western Canadian oil fields to the Lakehead System and a connecting carrier at Clearbrook, Minnesota. The purchase price for this transaction was approximately $35.4 million and was funded by a short-term loan at market rates from the General Partner. The terms of this acquisition were negotiated and approved by a special committee of independent directors who received independent legal and financial advice.

On January 29, 2002, the Partnership established two new unsecured credit facilities, a $300.0 million three-year term facility and a $300.0 million 364-Day facility, to replace the existing $350.0 million Revolving Credit Facility. Under the terms of these new facilities, the Partnership and the Operating Partnership may borrow funds up to a combined maximum of $300.0 million under the three-year term facility and a combined maximum of $300.0 million under the 364-Day Facility. In addition, when no default exists, the Partnership may designate any of its subsidiaries that is a material subsidiary to borrow under either or both the facilities and subject to complying with certain administrative procedures, it will be permitted to borrow. Any borrowings under either facility will be guaranteed by the Partnership, the Operating Partnership and any of its material subsidiaries, unless it is the borrower.

At the end of November 2001, the Partnership acquired the East Texas System for $230.5 million. A portion of the purchase price related to the acquisition of the East Texas System and the North Dakota System was financed with short term loans from the General Partner. In January 2002, these loans were refinanced with a subordinated loan payable to the General Partner which matures in January 2007. This loan bears interest at a floating market based rate and the Partnership has the right to repay the principal amount of this loan plus accrued interest at any time without penalty.

The Partnership has entered into hedge transactions to substantially mitigate exposure to movements in commodity prices which arise from the Partnership's investment in the East Texas System. Enbridge currently provides a guarantee of the obligations in respect of these hedging transactions. Under the terms of the guarantee, the Partnership has agreed to pay Enbridge a fee, which is based on a formula that is consistent with what third party financial institutions would charge for this form of guarantee.

PART IV

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) As to financial statements, supplementary information and financial statement schedules, reference is made to "Index to Financial Statements, Supplementary Information and Financial Statement Schedules" on page F-1 of this Report.

(b) The Partnership filed the following reports on Form 8-K during the fourth quarter of 2001: A report on Form 8-K was filed on November 19, 2001 attaching the consolidated statement of financial position of Enbridge Energy Company, Inc. A report on Form 8-K was also filed on November 21, 2001, attaching the Underwriting Agreement dated November 20, 2001 among the Partnership, Operating Partnership, Enbridge Energy Company, Inc,. and the underwriters named therein.

(c) The following Exhibits (numbered in accordance with Item 601 of Regulation S-K) are filed or incorporated herein by reference as part of this Report.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of the Partnership. (Partnership's Registration Statement No. 33-43425—Exhibit 3.1)
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (Partnership's 2000 Form 10-K/A dated October 9, 2001—Exhibit 3.2)
4.1	Form of Certificate representing Class A Common Units (Partnership's 2000 Form 10-K/A dated October 9, 2001—Exhibit 4.1)
4.2	Amended and Restated Agreement of Limited Partnership of the Partnership, dated April 15, 1997. (Registrant's Form 8-A/A, dated May 2, 1997)
4.3	Amendment to Amended and Restated Agreement of Limited Partnership, dated August 28, 2001 (Partnership's 2000 Form 10-K/A dated October 9, 2001—Exhibit 4.3)
10.1	Note Agreement and Mortgage, dated December 12, 1991. (1991 Form 10-K—Exhibit 10.1)
10.2	[Intentionally Omitted]
10.3	Distribution Support Agreement, dated December 27, 1991, among the Partnership, Lakehead Pipe Line Company, Inc. and Interprovincial Pipe Line Inc. (1991 Form 10-K—Exhibit 10.3)
10.4	Assumption and Indemnity Agreement, dated December 18, 1992, between Interprovincial Pipe Line Inc. and Interprovincial Pipe Line System Inc. (1992 Form 10-K—Exhibit 10.4)
10.5	Amended Services Agreement, dated February 29, 1988, between Interprovincial Pipe Line Inc. and Lakehead Pipe Line Company, Inc. (1991 Form 10-K—Exhibit 10.4)
10.6	Amended Services Agreement, dated January 1, 1992, between Interprovincial Pipe Line Inc. and Lakehead Pipe Line Company, Inc. (1992 Form 10-K—Exhibit 10.6)
10.7	Certificate of Limited Partnership of the Operating Partnership. (Partnership's Registration Statement No. 33-43425—Exhibit 10.1)
10.8	Certificate of Amendment to Certificate of Limited Partnership of the Operating Partnership. (Operating Partnership's 2000 Form 10-K/A dated October 9, 2001—Exhibit 10.8)
10.9	Amended and Restated Agreement of Limited Partnership of the Operating Partnership, dated December 27, 1991. (1991 Form 10-K—Exhibit 10.6)

Exhibit Number	Description
10.10	Amendment to Amended and Restated Agreement of Limited Partnership of the Operating Partnership, dated August 28, 2001. (Operating Partnership's Form 10-K/A dated October 9, 2001—Exhibit—10.10)
10.11	Certificate of Limited Partnership of Lakehead Services, Limited Partnership. (Partnership's Registration Statement No. 33-43425—Exhibit 10.4)
10.12	Amendment No. 1 to the Certificate of Limited Partnership of Lakehead Services, Limited Partnership. (Partnership's Registration Statement No. 33-43425—Exhibit 10.16)
10.13	Amended and Restated Agreement of Limited Partnership of Lakehead Services, Limited Partnership, dated December 27, 1991. (1991 Form 10-K—Exhibit 10.9)
10.14	Contribution, Conveyance and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership. (1991 Form 10-K—Exhibit 10.10)
10.15	LPL Contribution and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership and Lakehead Services, Limited Partnership. (1991 Form 10-K—Exhibit 10.11)
10.16	Services Agreement, dated January 1, 1996, between IPL Energy (U.S.A.) Inc. and Lakehead Pipe Line Company, Inc. (1995 Form 10-K—Exhibit 10.14)
10.17	Amended and Restated Revolving Credit Agreement, dated September 6, 1996, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P., Lakehead Services, Limited Partnership, Lakehead Pipe Line Company, Limited Partnership and the Bank of Montreal and Harris Trust and Savings Bank. (1996 Form 10-K—Exhibit 10.15)
10.18	First Amendment to Amended and Restated Revolving Credit Agreement, dated September 6, 1996, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P., Lakehead Services, Limited Partnership, Lakehead Pipe Line Company, Limited Partnership and the Bank of Montreal. (1996 Form 10-K—Exhibit 10.16)
10.19	Second Amendment to Amended and Restated Revolving Credit Agreement, dated June 16, 1998, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P., Lakehead Services Limited Partnership, Lakehead Pipe Line Company, Limited Partnership and Bank of Montreal, The Toronto Dominion Bank, Canadian Imperial Bank of Commerce, ABN AMRO Bank, N.V. Cayman Islands Branch and Bank of Montreal, as agent. (Form 10-Q/A, filed September 14, 1998—Exhibit 10.1)
10.20	Settlement Agreement, dated August 28, 1996, between Lakehead Pipe Line Company, Limited Partnership and the Canadian Association of Petroleum Producers and the Alberta Department of Energy. (1996 Form 10-K—Exhibit 10.17)
10.21	Promissory Note, dated as of September 30, 1998, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender. (1998 Form 10-K—Exhibit 10.19)
10.22	Treasury Services Agreement, dated January 1, 1996, between IPL Energy Inc. and Lakehead Pipe Line Company, Inc. (1996 Form 10-K—Exhibit 10.18)
10.23	Tariff Agreement as filed with the Federal Energy Regulatory Commission for the System Expansion Program II and Terrace Expansion Project. (1998 Form 10-K—Exhibit 10.21)

Exhibit Number	Description
10.24	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank. (1998 Form 8-K of Lakehead Pipe Line Company, Limited Partnership—Exhibit 4.1, dated October 20, 1998)
10.25	First Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank. (1998 Form 8-K of Lakehead Pipe Line Company, Limited Partnership—Exhibit 4.2, dated October 20, 1998)
10.26	Second Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank. (1998 Form 8-K of Lakehead Pipe Line Company, Limited Partnership—Exhibit 4.3, dated October 20, 1998)
10.27	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank. (1998 Form 8-K of Lakehead Pipe Line Company, Limited Partnership—Exhibit 4.4, dated October 20, 1998)
10.28	Promissory Note, dated as of March 31, 1999, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender. (1999 Form 10-K—Exhibit 10.26)
10.29	Third Supplemental Indenture dated November 21, 2000, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank. (2000 Form 8-K of Lakehead Pipe Line Company, Limited Partnership—Exhibit 4.2, dated November 16, 2000).
10.30	Credit Agreement dated January 29, 2002, among Enbridge Energy Partners, L.P., Enbridge Energy, Limited Partnership and Bank of America, N.A.,
10.31	364-Day Credit Agreement dated January 29, 2002, among Enbridge Energy Partners, L.P., Enbridge Energy, Limited Partnership and Bank of America, N.A.
21	Subsidiaries of the Registrant.
23.1	Consent of PricewaterhouseCoopers LLP.

All Exhibits listed above (with the exception of Exhibits 10.30, 10.31, 21, and 23.1 which are filed herewith) are incorporated herein by reference to the documents identified in parentheses.

Copies of Exhibits may be obtained upon written request of any Unitholder to Investor Relations, Enbridge Energy Company, Inc., 1100 Louisiana, Suite 3300, Houston, Texas 77002.

(d) As to financial statement schedules, reference is made to "Financial Statement Schedules" on page F-1 of this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

By: Enbridge Energy Company, Inc.,
as General Partner

By: /s/ DAN C. TUTCHER

Dan C. Tutcher
(President)

Date: February 22, 2002

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below on February 22, 2002 by the following persons on behalf of the Registrant and in the capacities indicated with the General Partner.

/s/ DAN C. TUTCHER
Dan C. Tutcher
President and Director
(Principal Executive Officer)

/s/ E.C. HAMBROOK
E.C. Hambrook
Director

/s/ J.R. BIRD
J. R. Bird
Director

/s/ J.L. BALKO
J.L. Balko
Chief Accountant
(Principal Financial and Accounting Officer)

/s/ C.A. RUSSELL
C.A. Russell
Director

/s/ P.D. DANIEL
P.D. Daniel
Director

/s/ G.K. PETTY
G.K. Petty
Director

/s/ D.P. TRUSWELL
D.P. Truswell
Director

INDEX TO FINANCIAL STATEMENTS, SUPPLEMENTARY INFORMATION AND FINANCIAL STATEMENT SCHEDULES

ENBRIDGE ENERGY PARTNERS, L.P.

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FINANCIAL STATEMENT SCHEDULES

Financial statement schedules not included in this Report have been omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Partners of
Enbridge Energy Partners, L.P.:

In our opinion, the accompanying consolidated statements of financial position and the related consolidated statements of income, of partners' capital, and of cash flows present fairly, in all material respects, the financial position of Enbridge Energy Partners, L.P. and its subsidiaries (the Partnership) at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Houston, Texas
January 24, 2002

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	Year ended December 31,		
	2001	2000	1999
	(In Millions, Except Per Unit Amounts)		
Revenues *(Note 10)*			
Transportation	$311.7	$305.6	$312.6
Energy marketing	26.1	—	—
Processing	2.6	—	—
	340.4	305.6	312.6
Expenses			
Power	49.9	47.4	53.0
Cost of natural gas	26.3	—	—
Operating and administrative	104.5	80.6	71.5
Depreciation	63.8	61.1	57.8
	244.5	189.1	182.3
Operating income	95.9	116.5	130.3
Interest and other income	2.8	4.8	3.4
Interest expense *(Note 8)*	(59.3)	(60.4)	(54.1)
Income before minority interest	39.4	60.9	79.6
Minority interest	(0.5)	(0.7)	(0.9)
Net income	$ 38.9	$ 60.2	78.7
Net income per unit *(Note 5)*	$ 0.98	$ 1.78	$ 2.48
Weighted average units outstanding	30.2	28.9	28.0

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	2001	2000	1999
		(In Millions)	
Cash provided from operating activities			
Net income	$ 38.9	$ 60.2	$ 78.7
Adjustments to reconcile net income to cash provided from operating activities:			
Depreciation	63.8	61.1	57.8
Interest on accrued rate refunds	—	—	0.7
Minority interest	0.5	0.7	0.9
Other	—	0.8	0.9
Changes in operating assets and liabilities:			
Accounts receivable and other	(23.1)	1.1	(3.2)
Oil overage balance	18.3	(4.2)	(3.1)
Materials and supplies	(0.1)	(0.3)	(0.3)
General Partner and affiliates	0.7	(3.2)	(1.2)
Accounts payable and other	23.2	(0.2)	(2.4)
Interest payable	0.3	0.2	0.8
Property and other taxes	(0.2)	1.1	1.4
Payment of rate refunds and related interest	—	—	(29.4)
	122.3	117.3	101.6
Investing activities			
Repayments from affiliate *(Note 9)*	3.0	1.6	24.5
Additions to property, plant and equipment	(35.0)	(21.7)	(82.9)
Change in construction payables	(2.1)	(0.6)	(32.7)
Asset acquisitions, net of cash acquired *(Note 3)*	(265.0)	—	—
	(299.1)	(20.7)	(91.1)
Financing activities			
Proceeds from unit issuances, net *(Note 1)*	171.3	—	119.7
Loans from Enbridge Energy Company, Inc. *(Note 3)*	176.2	—	—
Distributions to partners *(Note 4)*	(113.8)	(110.4)	(107.3)
Variable rate financing, net *(Note 8)*	(53.0)	(85.0)	(30.0)
Fixed rate financing, net *(Note 8)*	—	96.9	—
Other	(0.5)	0.2	—
Minority interest	(0.4)	(1.1)	0.1
	179.8	(99.4)	(17.5)
Increase (decrease) in cash and cash equivalents	3.0	(2.8)	(7.0)
Cash and cash equivalents at beginning of year	37.2	40.0	47.0
Cash and cash equivalents at end of year	$ 40.2	$ 37.2	$ 40.0

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31, 2001	December 31, 2000
	(In Millions, Except Unit Amounts)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 40.2	$ 37.2
Due from General Partner and affiliates	0.3	1.5
Accounts receivable and other	63.1	25.7
Oil overage balance	—	8.9
Advances to affiliate (*Note 9*)	2.9	5.9
Materials and supplies	8.5	7.7
	115.0	86.9
Property, plant and equipment, net (*Note 6*)	1,486.6	1,281.9
Other assets, net (*Note 7*)	47.6	7.9
	$1,649.2	$1,376.7
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Oil overage balance	$ 9.4	$ —
Accounts payable and other	48.5	17.4
Interest payable	6.8	6.5
Property and other taxes payable	14.4	14.4
Loans from Enbridge Energy Company, Inc. (*Note 3*)	176.2	—
Current portion of First Mortgage Notes	31.0	—
	286.3	38.3
Long-term debt (*Note 8*)	715.4	799.3
Contingencies (*Note 11*)		
Minority interest	3.3	3.2
	1,005.0	840.8
Partners' capital		
Class A common unitholders (Units authorized and issued—29,053,634 in 2001 and 24,990,000 in 2000)	577.0	488.6
Class B common unitholder (Units authorized and issued—3,912,750)	48.8	42.1
General Partner	6.5	5.2
Accumulated other comprehensive income (*Note 12*)	11.9	—
	644.2	535.9
	$1,649.2	$1,376.7

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	Class A Common Unitholders	Class B Common Unitholder	General Partner	Accumulated Other Comprehensive Income	Total
	(Dollars in Millions)				
Partners' capital at December 31, 1998	$453.4	$ 37.3	$ 4.3	$ —	$ 495.0
Allocation of net proceeds from unit issuance	106.2	12.4	1.1	—	119.7
Distributions to partners	(84.8)	(13.6)	(8.9)	—	(107.3)
Net income allocation	58.3	11.3	9.1	—	78.7
Partners' capital at December 31, 1999	533.1	47.4	5.6	—	586.1
Distributions to partners	(87.5)	(13.7)	(9.2)	—	(110.4)
Net income allocation	43.0	8.4	8.8	—	60.2
Partners' capital at December 31, 2000	488.6	42.1	5.2	—	535.9
Allocation of net proceeds from unit issuances (*Note 1*)	154.6	15.0	1.7	—	171.3
Distributions to partners	(90.6)	(13.7)	(9.5)	—	(113.8)
Subtotal	552.6	43.4	(2.6)	—	593.4
Net income allocation	24.4	5.4	9.1	—	38.9
Other comprehensive income:					
Gain on derivative financial instruments	—	—	—	11.9	11.9
Comprehensive Income	24.4	5.4	9.1	11.9	50.8
Partners' capital at December 31, 2001	$577.0	$ 48.8	$ 6.5	$11.9	$ 644.2

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

ENBRIDGE ENERGY PARTNERS, L.P.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(in millions, except per unit amounts)

1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS

Enbridge Energy Partners, L.P., formerly Lakehead Pipe Line Partners, L.P., (the "Partnership"), is a publicly traded limited partnership that was formed in 1991 to acquire, own and operate the crude oil and natural gas liquids pipeline business of Enbridge Energy Company, Inc., formerly Lakehead Pipe Line Company, Inc. (the "General Partner"). The General Partner is an indirect, wholly-owned subsidiary of Enbridge Inc. ("Enbridge") of Calgary, Alberta, Canada. The Partnership owns a 99% limited partner interest in Enbridge Energy, Limited Partnership, formerly Lakehead Pipe Line Company, Limited Partnership ("Operating Partnership"). Both are Delaware limited partnerships. The Operating Partnership owns the United States portion of the world's longest liquid petroleum pipeline ("Lakehead System"). During 2001, the Partnership acquired the assets of Enbridge Pipelines (North Dakota) L.L.C. ("North Dakota System") and assets in east Texas ("East Texas System"). The assets acquired are held in a series of limited liability companies and limited partnerships owned, directly or indirectly, 100% by Enbridge Energy Partners, L.P.

During the second quarter of 2001, the Partnership issued 1,813,634 Class A Common Units, which generated proceeds, net of issue expenses, of approximately $79.9 million. Proceeds from this offering were used to repay debt. On November 26, 2001, the Partnership completed the issuance of 2,250,000 Class A Common Units for net proceeds of $91.4 million. Proceeds from this offering were used to fund a portion of the East Texas System acquisition. After giving effect to the Class A Common Unit offerings, the General Partner has a 11.8% limited partner (in the form of 3,912,750 Class B Common Units) and 1.0% general partner interest in the Partnership, as well as a 1.0% general partner interest in the Operating Partnership.

The reporting segments of the Partnership represent its businesses of pipeline transportation, natural gas processing, and natural gas marketing activities. The transportation business, which transports crude oil and natural gas liquids through common carrier pipeline systems, is the most significant segment. The Lakehead System is the largest business in this segment.

The transportation segment includes the Lakehead System and the North Dakota System. The majority of shipments reach the Lakehead System at the Canada/United States border in North Dakota, through a Canadian pipeline system owned indirectly by Enbridge. Substantially all crude oil and natural gas liquids transported originate in western Canadian oil fields. Deliveries are made in the Great Lakes region of the U.S. and in the Province of Ontario, principally to refineries, either directly or through the connecting pipelines of other companies. The Partnership's natural gas processing segment includes natural gas treating and processing plants located in East Texas. The natural gas marketing segment primarily sells natural gas and related products to municipal utilities, industrial customers, and other third-party marketing companies and includes the related pipeline assets.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Partnership are prepared in accordance with generally accepted accounting principles. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures. Actual results could differ from those estimates and assumptions.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Principles of Consolidation

The financial statements of the Partnership include the accounts of the Partnership, the Operating Partnership and other wholly owned subsidiaries on a consolidated basis. The General Partner's 1.0% interest in the Operating Partnership is accounted for by the Partnership as a minority interest.

Regulation of Transportation Segment

As an interstate common carrier oil pipeline, rates and accounting practices of the Lakehead System and the North Dakota System are under the regulatory authority of the Federal Energy Regulatory Commission ("FERC"). The East Texas System is rate regulated by the Texas Railroad Commission on a complaint basis.

Revenue Recognition

Substantially all transportation pipeline system revenues are derived from transportation of crude oil, natural gas liquids ("NGLs") and natural gas and are recognized upon delivery. Natural gas gathering, treating and marketing revenues are recognized upon delivery of natural gas and related products.

Cash and Cash Equivalents

Cash equivalents are defined as all highly marketable securities with a maturity of three months or less when purchased. They are accounted for as held-to-maturity securities and valued at amortized cost.

Oil Overage Balance

Represents oil owed to, or receivable from, customers of the pipeline system. The balance also includes crude oil retained by the pipeline under terms of its transportation tariff.

Materials and Supplies

Materials and supplies are stated at cost.

Deferred Financing Charges

Deferred financing charges are amortized on the straight-line basis over the life of the related debt, which is comparable to results using the effective interest method.

Property, Plant and Equipment

Property, plant and equipment is stated at cost. Expenditures for system expansion and major renewals and betterments are capitalized; maintenance and repair costs are expensed as incurred. Interest incurred on external borrowings during construction is capitalized. Depreciation of property, plant and equipment is provided on the straight-line basis over estimated service lives. For all segments, when property, plant and equipment are disposed of, the cost less net proceeds is normally charged to accumulated depreciation and no gain or loss on disposal of property is recognized.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Goodwill and Other Intangible Assets

Goodwill represents the excess of cost over fair value of assets of businesses acquired. Other intangible assets, primarily consisting of shipper contracts acquired on the East Texas System, are amortized on a straight-line basis over the life of the underlying assets. The Partnership tests goodwill and other intangible assets periodically to determine whether an impairment has occurred. An impairment occurs when the carrying amount of an asset exceeds the fair value of the recognized goodwill or intangible asset. If impairment has occurred, the loss is recorded in the period.

Income Taxes

The Partnership is not a taxable entity for federal and state income tax purposes. Accordingly, no recognition has been given to income taxes for financial reporting purposes. The tax on Partnership net income is borne by the individual partners through the allocation of taxable income. Net income for financial statement purposes may differ significantly from taxable income of Unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under the Partnership Agreement. The aggregate difference in the basis of the Partnership's net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner's tax attributes in the Partnership is not available to the Partnership.

Derivative Financial Instruments

The Partnership recognizes all derivative financial instruments as assets and liabilities and measures them at fair value. For derivative financial instruments that are designated and qualify as a cash flow hedge, the effective portions of changes in fair value of the derivative are recorded in other comprehensive income and are recognized in the income statement when the hedged item affects earnings. Changes in the fair value of derivatives that do not qualify for hedge treatment are recognized currently in earnings. The related cash flows from those derivative financial instruments accounted for as hedges are classified in the same category as the items being hedged.

Net income and cash flows are subject to volatility stemming mainly from changes in interest rates, natural gas prices, and fractionation margins. In order to manage the risks to Partnership unitholders, the General Partner uses a variety of derivative financial instruments to create offsetting positions to specific commodity or interest rate exposures. All of these financial instruments are employed in connection with an underlying asset, liability or anticipated transaction and are not used for speculative purposes. In implementing its hedging programs, the General Partner has established a formal analysis and execution framework that requires the approval of the Board of Directors of the General Partner, or a committee of senior management.

Derivative financial instruments are used primarily to hedge against the effect of future interest rate movements, to manage natural gas purchases on the East Texas System that are related to regional natural gas prices, and to hedge fractionation margins associated with the East Texas System processing assets. (See Note 12 to the Consolidated Financial Statements.)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Comparative Amounts

Certain reclassifications have been made to the prior years reported amounts to conform to the classifications used in the 2001 consolidated financial statements. These reclassifications have no impact on net income.

New Accounting Pronouncements

In June 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." This Statement requires that all derivatives be recognized at fair value in the balance sheet and all changes in fair value be recognized currently in earnings or deferred as a component of other comprehensive income, depending on the intended use of the derivative. The Partnership adopted SFAS No. 133 on January 1, 2001.

In June 2001, the FASB issued SFAS No. 141, "Business Combinations." This Statement requires the use of the purchase method for all business combinations. In addition, it requires the reassessment of intangible assets to determine if they are appropriately classified either separately or within goodwill. This Statement is effective for business combinations initiated after June 30, 2001. The Partnership adopted SFAS No. 141 on July 1, 2001 with no impact on results of operations, financial position or cash flows.

In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets". Under SFAS No. 142, goodwill and intangible assets with indefinite lives will not be amortized but will be reviewed for impairment at least annually. Intangible assets with finite lives will continue to be amortized over their useful lives, which will not be limited to a maximum life of forty years. The Partnership adopted SFAS No. 142 on January 1, 2002. This standard is not expected to have a material impact on results of operations, financial position or cash flows. With the adoption of SFAS No. 142, goodwill of $15.0 million is no longer subject to amortization over its estimated useful life.

Also in July 2001, the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations" under which retirement obligations will be recognized at fair value in the period they are incurred. When the liability is initially recorded, the cost is capitalized by increasing the asset's carrying value, which is subsequently depreciated over its useful life. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. The Partnership is currently evaluating the potential effects if any, of adopting SFAS No. 143, on its financial condition and results of operations as well as the timing of its adoption.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". SFAS No. 144 establishes a single accounting model for long-lived assets to be disposed of by sale. The Statement retains most of the requirements in SFAS No. 121 related to the recognition of impairment of long-lived assets to be held and used. The Partnership adopted SFAS No. 144 on January 1, 2002. This standard is not expected to have a material impact on results of operations, financial position or cash flows.

(in millions, except per unit amounts)

3. ACQUISITIONS

On November 30, 2001, the Partnership acquired natural gas gathering, transportation, processing and marketing assets in east Texas. The assets were purchased for cash of $230.0 million plus estimated transaction costs of $0.5 million. The purchase was funded by the issuance of Class A Common Units with total net proceeds of $91.4 million and a short-term loan at market rates from the General Partner. The value allocated to the assets was determined by agreement between the parties and supported by an independent appraisal. Goodwill associated with the acquisition is $15.0 million, and is allocated entirely to the Partnership's marketing segment. Customer contracts are comprised entirely of natural gas purchase and sale contracts and are allocated entirely to the Partnership's marketing segment.

The allocation of the purchase price is as follows.

Gathering and Transportation Assets	$180.5
Processing Assets	20.0
Customer Contracts	15.0
Goodwill	15.0
Total	$230.5

The consolidated financial statements include the results of operations from, and the estimated fair value of assets at, the date of acquisition.

Unaudited pro forma net income for the twelve months ended December 31, 2001 and December 31, 2000 is estimated to be $44.0 and $65.7 million, respectively. These estimates assume the acquisition of the East Texas System had occurred on January 1, 2001 and January 1, 2000, respectively, and represent the combined results of operations for each of the years ending December 31, 2001 and 2000. The unaudited pro forma financial results have been prepared for comparative purposes only and may not be indicative of results that would have occurred if the Partnership had acquired the assets as of January 1 of either year. Pro forma results for the year-ended 1999 are not representative due to significant natural gas volume increases since 1999.

On May 18, 2001, the Partnership completed its acquisition of the assets of Enbridge Pipelines (North Dakota) L.L.C. for cash of $35.4 million, including working capital and transaction costs. This acquisition was accounted for using the purchase method. North Dakota System results of operations have been included in earnings from the date of the acquisition. The purchase price has been allocated to current assets, liabilities and to property, plant and equipment on the basis of estimated fair values with property, plant and equipment being depreciated over the economic life of the assets. No goodwill or intangible assets were recognized in the acquisition. The acquisition was funded by a short-term loan from the General Partner.

4. CASH DISTRIBUTIONS

The Partnership distributes quarterly all of its "Available Cash", which is generally defined in the Partnership Agreement as cash receipts less cash disbursements and net additions to reserves for future requirements. These reserves are retained to provide for the proper conduct of the Partnership business and as necessary to comply with the terms of any agreement or obligation of the Partnership. Distributions by the Partnership of its Available Cash generally are made 98.0% to the Class A and B

(in millions, except per unit amounts)

4. CASH DISTRIBUTIONS (Continued)

Common Unitholders and 2.0% to the General Partner, subject to the payment of incentive distributions to the General Partner to the extent that certain target levels of cash distributions to the Unitholders are achieved. The incremental incentive distributions payable to the General Partner are 15.0%, 25.0% and 50.0% of all quarterly distributions of Available Cash that exceed target levels of $0.59, $0.70, and $0.99 per Class A and B Common Units, respectively.

In 2001 and 2000, the Partnership paid cash distributions of $3.50 per unit, consisting of $0.875 per unit paid in February, May, August and November. In 1999, the Partnership paid cash distributions of $3.485 per unit, consisting of $0.86 per unit paid in February and $0.875 per unit paid in May, August and November.

5. NET INCOME PER UNIT

Net income per unit is computed by dividing net income, after deduction of the General Partner's allocation, by the weighted average number of Class A and Class B Common Units outstanding. The General Partner's allocation is equal to an amount based upon its 1.0% general partner interest, adjusted to reflect an amount equal to incentive distributions and an amount required to reflect depreciation on the General Partner's historical cost basis for assets contributed on formation of the Partnership. Net income per unit was determined as follows.

	Year ended December 31,		
	2001	2000	1999
Net income	$38.9	$60.2	$78.7
Net income allocated to General Partner	(0.4)	(0.6)	(0.8)
Incentive distributions and historical cost depreciation adjustments	(8.7)	(8.2)	(8.3)
	(9.1)	(8.8)	(9.1)
Net income allocable to Common Units	$29.8	$51.4	$69.6
Weighted average units outstanding (millions)	30.2	28.9	28.0
Net income per unit	$ 0.98	$ 1.78	$ 2.48

(in millions, except per unit amounts)

6. PROPERTY, PLANT AND EQUIPMENT, NET

	December 31,		
	Depreciation Rates	2001	2000
Land	—	$ 7.8	$ 6.4
Rights-of-way	3.8% - 4.35%	132.4	109.8
Pipeline	3.6% - 4.35%	1,111.5	957.9
Pumping equipment, buildings and tanks	4.2% - 4.35%	482.4	470.1
Compressors, meters, and other operating equipment	4.00%	15.6	—
Vehicles, office furniture and equipment	8.15% - 25.0%	38.7	34.3
Processing and treater plants	4.00%	41.8	—
Construction in progress	—	25.9	10.0
		1,856.1	1,588.5
Accumulated depreciation		(369.5)	(306.6)
		$1,486.6	$1,281.9

Depreciation rates utilized by the Lakehead System were approved by the Federal Energy Regulatory Commission, effective January 1, 1999, coinciding with the in-service date for the Partnership's system expansion programs.

Depreciation rates for the North Dakota System and the East Texas System are based on the lesser of the estimated remaining service lives of the properties or the estimated remaining life of crude oil or natural gas production in the basins served by the pipelines.

7. OTHER ASSETS, NET

	December 31,	
	2001	2000
Customer Contracts	$15.0	$ —
Goodwill	15.0	—
Other	17.6	7.9
	$47.6	$7.9

(in millions, except per unit amounts)

8. DEBT

	December 31, 2001	December 31, 2000
First Mortgage Notes	$310.0	$310.0
Revolving Credit Facility Agreement	137.0	190.0
Senior Unsecured Notes, Net	299.4	299.3
	$746.4	$799.3
Current portion	(31.0)	—
	$715.4	$799.3

First Mortgage Notes

The First Mortgage Notes (“Notes”) are secured by a first mortgage on substantially all of the property, plant and equipment of the Operating Partnership and are due and payable in ten equal annual installments beginning December 2002. The interest rate on the Notes is 9.15% per annum, payable semi-annually. The Notes contain various restrictive covenants applicable to the Partnership, and restrictions on the incurrence of additional indebtedness, including compliance with certain issuance tests. The General Partner believes these issuance tests will not negatively impact the Partnership’s ability to finance future expansion projects. Under the Note Agreements, the Partnership cannot make cash distributions more frequently than quarterly in an amount not to exceed Available Cash (Note 4) for the immediately preceding calendar quarter. If the notes were to be paid prior to their stated maturities, the Note Agreements provide for the payment of a redemption premium by the Partnership.

Revolving Credit Facility Agreement

As of December 31, 2001, Partnership had a $350.0 million Revolving Credit Facility Agreement scheduled to mature in September 2005. Upon drawdown, the loans are secured by a first lien on the mortgaged property that ranks equally with the Notes or may be fully collateralized with U.S. or Canadian government securities. The facility contains restrictive covenants substantially identical to those in the Note Agreements, provides for borrowing at variable interest rates and has a facility fee of 0.10% (2000—0.10%) per annum on the entire $350.0 million. At December 31, 2001, $137.0 million of the facility was utilized and was classified as long-term debt (2000—$190.0 million). The interest rate on loans averaged 5.3% (2000—6.7%; 1999—5.4%) for the year and was 2.3% at the end of 2001 (2000—6.2%).

On January 29, 2002, the Partnership established two new unsecured credit facilities, a $300.0 million three-year term facility and a $300.0 million 364-Day facility, to replace the existing $350.0 million Revolving Credit Facility. Under the terms of these new facilities, the Partnership and the Operating Partnership may borrow funds up to a combined maximum of $300.0 million under the three-year term facility and a combined maximum of $300.0 million under the 364-Day Facility. In addition, when no default exists, the Partnership may designate any of its subsidiaries that is a material subsidiary to borrow under either or both the facilities and subject to complying with certain administrative procedures, it will be permitted to borrow. Any borrowings under either facility will be

(in millions, except per unit amounts)

8. DEBT (Continued)

guaranteed by the Partnership, the Operating Partnership and any of its material subsidiaries, unless it is the borrower. Upon closing, indebtedness under the $350.0 million Revolving Credit Facility was refinanced with indebtedness drawn under the new credit facilities and the $350.0 million Revolving Credit Facility was terminated.

Senior Unsecured Notes

The Operating Partnership has issued a total of $300 million of senior unsecured notes. The notes pay interest semi-annually and have varying maturities and terms as outlined in the table below. The senior unsecured notes do not contain any covenants restricting the issuance of additional indebtedness.

	December 31,		
Senior Unsecured Notes	**Interest Rate**	**2001**	**2000**
Notes maturing in 2012	7.900%	$100.0	$100.0
Notes maturing in 2018	7.000%	100.0	100.0
Notes maturing in 2028	7.125%	100.0	100.0
Unamoritized Discount		(0.6)	(0.7)
		$299.4	$299.3

Interest

Interest expense is net of amounts capitalized of $0.3 million (2000—$0.3 million; 1999—$4.4 million). Interest paid amounted to $57.0 million (2000—$59.4 million; 1999—$56.1 million).

Debt Service Reserve

Under the terms of the First Mortgage Notes and the Revolving Credit Facility in place at December 31, 2001, the Partnership is required to establish at the end of each quarter a debt service reserve in an amount equal to 50% of the prospective debt service payments for the immediate following calendar quarter. At December 31, 2001, the debt service reserve was $1.0 million (2000—$0.8 million).

The aggregate long-term maturities for the five years ending December 31, 2002 through 2006 are $31.0 million per year of First Mortgage Notes and $137.0 million borrowed on the Revolving Credit Facility in 2005.

9. RELATED PARTY TRANSACTIONS

The Partnership, which does not have any employees, uses the services of the General Partner and its affiliates for managing and operating its pipeline business. These services, which are reimbursed at cost in accordance with service agreements, amounted to $36.9 million (2000—$30.3 million; 1999—$34.3 million) and are included in operating and administrative expenses. At December 31, 2001, the Partnership has accounts receivable from the General Partner and affiliates of $0.3 million. At December 31, 2000, the Partnership had accounts receivable from the General Partner and affiliates of $1.5 million.

(in millions, except per unit amounts)

9. RELATED PARTY TRANSACTIONS (Continued)

The Partnership has entered into an easement acquisition agreement with Enbridge Holdings (Mustang) Inc. ("Enbridge Mustang"), an affiliate of the General Partner. Enbridge Mustang acquired certain real property for the purpose of granting pipeline easements to the Partnership for construction of a new pipeline, completed during 1998, by the Partnership from Superior, Wisconsin to Chicago, Illinois. In order to provide for these real property acquisitions by Enbridge Mustang, the Partnership had made non-interest bearing cash advances to Enbridge Mustang. As Enbridge Mustang disposes of the real property, the advances are repaid. The advances amounted to $2.9 million at December 31, 2001 (2000—$5.9 million). Under the terms of the agreement, the Partnership will reimburse Enbridge Mustang the net cost of acquiring, holding and disposing of the real property.

The Partnership has entered into an agreement with Tidal Energy Marketing Inc. ("Tidal") in which Enbridge Inc. has a 50% interest. Tidal is engaged in the business of crude oil and condensate marketing, transportation, storage and trading and providing related services. The agreement gives Tidal the ability to act as the Partnership's agent in the leasing of the Partnership's terminalling and storage facility, consisting of nine 100,000 barrels ("bbl") nominal capacity tanks and related facilities. The Partnership pays Tidal a monthly fee which includes 50% of the distributable proceeds from the tank leases. In 2001, the Partnership paid Tidal $0.3 million, (2000, $0.1 million).

A portion of the purchase price related to the acquisition of the East Texas System and the North Dakota System was financed with short term loans from the General Partner. In January 2002, these loans were refinanced with a subordinated loan payable to the General Partner which matures in January 2007. This loan bears interest at a floating market based rate and the Partnership has the right to repay the principal amount of this loan plus accrued interest at any time, without penalty.

The Partnership has entered into hedge transactions to substantially mitigate exposure to movements in commodity prices which arise from the Partnership's investment in the East Texas System. Enbridge currently provides a guarantee of the obligations in respect of these hedging transactions. Under the terms of the guarantee, the Partnership has agreed to pay Enbridge a fee, which is based on a formula that is consistent with what third party financial institutions would charge for this form of guarantee.

10. MAJOR CUSTOMERS

Operating revenue received from major customers was as follows:

	Year ended December 31,		
	2001	2000	1999
BP Canada Energy Company	$73.4	$69.6	$71.9
ExxonMobil Canada Energy	$59.7	$48.3	$42.2
PDV Midwest	$21.4	$33.7	$23.7
Imperial Oil Limited	$24.0	$23.3	$33.3

The Partnership has a concentration of trade receivables from companies operating in the oil and gas industry. These receivables are collateralized by the crude oil and other products contained in the Partnership's pipeline and storage facilities.

11. CONTINGENCIES

Environment

The Partnership is subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid and gas pipeline operations and the Partnership could, at times, be subject to environmental cleanup and enforcement actions. The General Partner manages this environmental risk through appropriate environmental policies and practices to minimize the impact to the Partnership. To the extent that the Partnership is unable to recover environmental costs in its rates, to the extent not recovered through insurance, the General Partner has agreed to indemnify the Partnership from and against any costs relating to environmental liabilities associated with the Lakehead System assets prior to the transfer to the Partnership in 1991. This excludes any liabilities resulting from a change in laws after such transfer. The Partnership continues to voluntarily investigate past leak sites on the Lakehead, North Dakota and East Texas Systems for the purpose of assessing whether any remediation is required in light of current regulations, and to date no material environmental risks have been identified.

Oil and Gas in Custody

The Partnership's Lakehead System and North Dakota assets transport crude oil and NGLs owned by its customers for a fee. The volume of liquid hydrocarbons in the Partnership's pipeline system at any one time approximates 14 million barrels, virtually all of which is owned by the Partnership's customers. Under terms of the Partnership's tariffs, losses of crude oil not resulting from direct negligence of the Partnership may be apportioned among its customers. In addition, the Partnership maintains adequate property insurance coverage with respect to crude oil and NGLs in the Partnership's custody.

Approximately 30% of the natural gas volume on the East Texas System is transported by customers on their contract with the remaining 70% purchased by the Partnership and sold to third parties downstream of the purchase point. The value of customer natural gas in custody of the East Texas System is not material to the Partnership.

12. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The carrying amounts of cash equivalents approximate fair value because of the short-term maturities of these investments.

Based on the borrowing rates currently available for instruments with similar terms and remaining maturities, the carrying value of borrowings under the Revolving Credit Facility approximate fair value, the fair value of the First Mortgage Notes approximates $342.6 million (2000—$346.5 million) and the fair value of the Senior Unsecured Notes approximates $291.4 million (2000—$290.3 million). Due to defined contractual make-whole arrangements, refinancing of the First Mortgage Notes and Senior Unsecured Notes would not result in any financial benefit to the Partnership.

12. FINANCIAL INSTRUMENTS (Continued)

Fair Value of Derivative Financial Instruments

Interest rate risk:

The Partnership enters into interest rate swaps to manage the effect of future interest rate movements on its interest costs. These agreements, maturing July 2002, meet the criteria for hedge accounting and are treated as cash flow hedges. On January 1, 2001, the Partnership recorded an unrealized loss of $0.1 million charged to Other Comprehensive Income, representing the transition adjustment for the cash flow hedges. During the year ended December 31, 2001, this payable increased to $1.9 million due to revaluation of the floating to fixed interest rate swaps and the entire amount is reflected in Other Comprehensive Income.

Realized gains and losses on financial instruments used to hedge the Partnership's exposure to changes in future interest rates are recognized currently with the related interest expense.

Natural gas price risk:

Earnings and cash flows of the East Texas System are sensitive to changes in the price of natural gas and fractionation margins. To mitigate volatility of cash flows, the Partnership enters into derivative financial instruments to manage its exposures. Gains and losses on cash flow hedging instruments are reflected in other comprehensive income and recognized in net income in the periods when the underlying transaction occurs. If the derivative financial instrument is no longer effective as a hedge, the Partnership will recognize future changes in the value of the financial instrument in net income.

To hedge cash flow volatility associated with the East Texas System natural gas sales, at December 31, 2001, the Partnership has outstanding derivative financial instruments hedging 9,000 MMBtu/day of natural gas for a period approximating 10 years. The fair value of these contracts at December 31, 2001, is approximately $8.5 million receivable. The entire amount of the corresponding gain is recorded in Other Comprehensive Income.

For the benefit of its customers, the East Texas System will enter into fixed price natural gas purchase contracts. No price risk is assumed by the East Texas System as simultaneous derivative financial instruments are put in place at the same time the customer contract is entered into. At December 31, 2001, the fair value of these derivative financial instruments is $6.8 million receivable.

To hedge against unfavorable changes in processing fractionation margins, the Partnership has entered into a series of derivative financial instruments to sell components of natural gas liquids (ethane, propane, butane, condensate) through November 30, 2002. These hedges are done in conjunction with natural gas price hedges for 15,000 MMBtu/d to buy natural gas to hedge costs associated with processing liquids from the raw natural gas stream. Collectively, the value of these contracts at December 31, 2001 is approximately $1.5 million payable. The entire amount of the corresponding loss is recorded in Other Comprehensive Income.

The financial instruments described above meet the criteria for hedge accounting and are treated as cash flow hedges with related gains or losses on the contracts recorded as operating revenue when the underlying transaction occurs.

At December 31, 2001, no material credit risk exposure existed as the General Partner enters into financial instruments only with creditworthy institutions that possess investment grade ratings.

(in millions, except per unit amounts)

13. SEGMENT INFORMATION

The Partnership's operations are segmented based on the type of business activity and management control. The Partnership's transportation pipelines primarily receive, and deliver, crude oil, liquid hydrocarbons, natural gas, and natural gas liquids to, and from, other pipelines, refineries and provide gathering functions in certain areas.

The Partnership provides marketing services to its customers. The Partnership's marketing activities include providing natural gas supply and sales services to some of its end-user customers by purchasing the natural gas supply from other marketers, pipeline affiliates, and natural gas producers and reselling the natural gas to the end-user. Natural gas processing revenues are realized from the extraction and sale of NGLs as well as the sale of the residual natural gas.

The "Other" column consists of costs of financing, interest income and minority interest, which are not allocated to the other business segments.

The following table presents certain financial information relating to the Company's business segments as of or for the year ended December 31, 2001. As discussed in Note 3 to the Consolidated Financial Statements, the results from the East Texas System were included since November 30, 2001. Comparative segment information for years 2000 and 1999 is not comparable, as a result of the Partnership having only one segment in prior years. December 2001 results for gas pipeline marketing and processing are not representative of full year expectations due to a maintenance shut down during the month.

	As of or for the Year Ended December 31, 2001				
	Transportation	Marketing	Processing	Other	Totals
Operating revenues	$ 311.7	$ 26.1	$ 2.6	$ —	$ 340.4
Power	49.9	—	—	—	49.9
Cost of natural gas	—	24.1	2.2	—	26.3
Operating and administrative	102.9	1.4	0.2	—	104.5
Depreciation	63.1	0.6	0.1	—	63.8
Operating Income	95.8	—	0.1	—	95.9
Interest and other	—	—	—	2.8	2.8
Interest expense	—	—	—	(59.3)	(59.3)
	95.8	—	0.1	(56.5)	39.4
Minority interest	—	—	—	(0.5)	(0.5)
Net income	95.8	—	0.1	(57.0)	38.9
Total Assets	1,393.8	212.3	43.1	—	1,649.2
Capital Expenditures (excluding acquisitions)	35.0	—	—	—	35.0

ENBRIDGE ENERGY PARTNERS, L.P.

SUPPLEMENTARY INFORMATION (UNAUDITED)
SELECTED QUARTERLY FINANCIAL DATA
(Dollars in Millions, Except Per Unit Amounts)

2001 Quarters	First	Second	Third	Fourth	Total
Operating revenue	$71.9	$81.1	$75.9	$111.5	$340.4
Operating income	$24.7	$25.9	$20.5	$ 24.8	$ 95.9
Net income	$10.1	$11.6	$ 6.6	$ 10.6	$ 38.9
Net income per unit(1)	$ 0.27	$ 0.32	$ 0.13	$ 0.26	$ 0.98

2000 Quarters	First	Second	Third	Fourth	Total
Operating revenue	$78.8	$78.3	$74.9	$ 73.6	$305.6
Operating income	$33.3	$31.2	$29.0	$ 23.0	$116.5
Net income	$20.1	$16.5	$14.2	$ 9.4	$ 60.2
Net income per unit(1)	$ 0.62	$ 0.49	$ 0.42	$ 0.25	$ 1.78

(1) The General Partner's allocation of net income has been deducted before calculating net income per unit.